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Peak Demand Impacts From Electricity Efficiency Programs

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November 2019

This work was supported by the U.S. Department of Energy's Office of Electricity, Transmission Permitting and Technical Assistance Division, under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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The authors thank the following colleagues for their input on study approach or review of a draft of this report, or both: Amanda Best (Maryland Public Service Commission), Danielle Byrnett (National Association of Regulatory Utility Commissioners), John Cavalli (Itron), Tom Eckman (consultant), Rachel Gold (American Council for an Energy-Efficient Economy), Therese Harris (Texas Public Utilities Commission), Daniel Hurley (Maryland Public Service Commission), Sami Khawaja (Cadmus), Lark Lee (Tetra Tech), Rebecca Lim (Colorado Public Utilities Commission), Joe Loper (Itron), Larry Mansueti (U.S. Department of Energy), Gabe Munoz (Entergy Arkansas LLC), Luke Nickerman (Pacific Gas & Electric), Steve Schiller (Berkeley Lab), Rodney Sobin (National Association of State Energy Officials), Greg Thomas (Performance Systems Development), Vanessa Ulmer (New York State Energy Research and Development Authority), Henry Yoshimura (ISO-New England), and Jason Peuquet (Colorado Public Utilities Commission).

All opinions, errors and omissions remain the responsibility of the authors. All reference URLs were accurate as of the date of publication.

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Acronyms and Abbreviations

C&I	Commercial and Industrial
CSE	Cost of Saving Electricity
CSPD	Cost of Saving Peak Demand
DER	Distributed Energy Resource
DOE	U.S. Department of Energy
DSM	Demand-Side Management
EM&V	Evaluation, Measurement and Verification
FERC	Federal Energy Regulatory Commission
HVAC	Heating, Air Conditioning and Ventilation
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
NYSERDA	New York State Energy Research & Development Authority
NYISO	New York Independent System Operator
PA	Program Administrator
PUC	Public Utility Commission
PUCT	Public Utility Commission of Texas
RTO	Regional Transmission Organization
TRM	Technical Reference Manual
WACC	Weighted-Average Cost of Capital

Executive Summary

Quantification of the costs and benefits of electricity efficiency programs have focused largely on the economic value of *annual* energy reductions. State public utility commissions (PUCs) and utilities are increasingly interested in assessing peak demand impacts of these programs. The U.S. Energy Information Administration defines peak demand as "The maximum load during a specified period of time."[1] In practice, utilities and grid operators use a wide range of definitions for peak demand.[2]

With increasing need for a more flexible and resilient electricity system, and changing costs for generation, utilities and other efficiency program administrators must take into account all characteristics of efficiency programs — including peak demand reduction — to ensure a reliable system at the most affordable cost.

In this study, Berkeley Lab explored a new metric, the first-year *program administrator cost of saving peak demand* (PA CSPD). We collected data on costs, energy savings and peak demand savings for electricity efficiency programs for 36 investor-owned utilities and other PAs[3] in nine states (Arizona, Arkansas, California, Colorado, Illinois, Massachusetts, Maryland, New York, and Texas) for 2014 to 2017. While some utilities report demand reductions for their electricity efficiency programs, there has been little sustained effort in the United States to gather peak demand reduction data or benchmark the cost of achieving peak demand impacts. As a first of its kind analysis, we developed a framework for analyzing peak demand savings across utilities and states and begin to quantify the first-year cost of saving peak demand.

We first calculated the *PA cost of saving electricity* (PA CSE) for each individual program in our dataset and used these values as points of reference throughout. Expressed in dollars per kilowatt-hour (kWh) of electricity savings, this metric measures activities from a utility's perspective. Several Berkeley Lab studies have documented this metric.[4] We then calculated the first-year PA CSPD — expressed in dollars per kilowatt (kW) — at the state level and for specific programs. We also analyzed this metric by climate zone to assess how it varies for programs with weather-sensitive measures. The savings-weighted PA CSE during the study period averages $0.029/kilowatt-hour (kWh) and varies by a factor of three ($0.013/kWh to $0.039/kWh) across the nine states. The first-year savings-weighted PA CSPD averages $1,483/kilowatt (kW) and varies more than four-fold ($568/kW to $2,353/kW). Comparing the range in values for these two metrics illustrates that program costs are the primary driver of differences in the first-year PA CSPD across states, although the level of peak demand savings (per program dollar invested) appears to have some impact as well.

[1] www.eia.gov/tools/glossary/index.php.
[2] See Table B - 2 in Appendix B.
[3] In some states, third parties administer these programs. However, utilities administer most programs, so we use the term "utilities" for convenience throughout this report. Table B - 4 in Appendix B provides a list of PAs in our dataset.
[4] See Hoffman et al. 2018; Schwartz et al. 2019.

Based on this initial study, electricity efficiency programs appear to be a relatively low-cost way for utilities to meet peak demand, compared to the capital cost of other resources (Lazard 2018; EIA 2019) that can be used to meet peak demand. However, many energy efficiency technologies, such as more efficient light bulbs, are "passive" and are not dispatchable. In such cases, efficiency resources do not provide the same services as a natural gas peaking turbine, making comparisons between these resources complex. At the same time, our results suggest that electricity efficiency programs that reduce peak demand merit strong consideration by utilities and regional grid operators. Further, "active" efficiency measures such as lighting controls enable active management of efficiency resources, offering additional grid services.

We summarize the first-year PA CSPD for selected types of efficiency programs for a portion of our dataset:[5] residential heating, air conditioning, and ventilation (HVAC); residential lighting; whole-home retrofit programs; low-income programs; programs targeted at small commercial customers; prescriptive rebates for medium and large commercial and industrial (C&I) customers; and custom rebate programs for large C&I customers. These seven program types account for 58% of total peak demand savings of our dataset. Importantly, these types of programs are designed for kWh reductions; they also happen to reduce peak load.

Residential lighting programs have the lowest first-year PA CSPD across the utilities studied ($730 to $740/kW), followed by prescriptive rebates for medium and large C&I customers ($1,330/kW). Several programs — whole home retrofit, small C&I programs and residential HVAC — have savings-weighted average or median values in the $1,800 to $2,500/kW range. Results are more difficult to explain for C&I custom rebate programs, with a first-year median PA CSPD of $1,780/kW and savings-weighted average of $3,340/kW — almost twice as high. A possible explanation for the difference between median and savings-weighted average values is that C&I custom programs are heterogeneous among utilities (e.g., some programs focus on installing HVAC equipment and controls for commercial customers; others target process improvement projects for industrial customers).

We identify opportunities and next steps to improve future analysis of the PA CSPD, focusing on issues that hinder efforts to estimate this metric. These issues include inconsistent methods to calculate peak demand reductions, inconsistencies in reporting, different definitions of peak demand periods, missing data on peak period savings, and accuracy and sources for coincidence factors used to quantify peak demand savings. Peak demand savings data from additional states also are required to provide broader geographic representation, larger sample size, and more diversity. Additional research also is needed on definitions and calculations to increase confidence in results. Further work in these areas will help utilities and PUCs assess cost performance of efficiency programs and design and implement them cost-effectively.

[5] Specifically, program years for which peak demand (kW) savings data are reported (1,901 program years).

Ultimately, electricity efficiency programs can more robustly serve as peak demand reduction resources for the bulk power system, as well as for transmission and distribution, with increased efforts to measure and verify their location- and time-sensitive demand impacts.

1. Introduction

Energy efficiency can reduce both annual energy consumption and peak demand for electric power systems. Historically, electric utilities in most states have paid more attention to quantifying the cost and value of first-year and lifetime energy savings of electricity efficiency programs they operate, rather than peak demand impacts.[6] However, utilities and state PUCs in a number of states are starting to assess and report the peak demand impacts of these programs. This phenomenon is driven primarily by: (1) state-level policy drivers, (2) design of centrally organized wholesale energy and capacity markets, and (3) increasing penetration of distributed energy resources (DERs) and their impact on distribution system needs, as well as on the bulk power system.

With respect to policy drivers, Texas was the first state to adopt an energy efficiency resource standard (in 1999). The state required electric utilities to offset 10% of load growth in peak demand through end-use energy efficiency (Texas Legislature 1999). In 2007, after several years of meeting this goal, the state legislature increased the standard to require electric utilities to offset 15% of load growth by the end of 2008 and 20% of load growth by the end of 2009 (Texas Legislature 2007). The savings targets are expressed in terms of peak demand reductions, and the utilities and PUC of Texas have devoted significant efforts to improving the consistency of approaches used to estimate peak demand reductions across measures in the state technical reference manual (TRM) (PUCT 2018).[7] Pennsylvania enacted an energy efficiency resource standard in 2008 that included both energy savings and peak demand reduction targets. In 2012, the Pennsylvania PUC directed the utilities to continue to track and report demand reduction benefits from installed energy efficiency measures (PA PUC 2012, 2015). Six states (Hawaii, Massachusetts, Michigan, New York, Rhode Island, and Vermont) provide an opportunity for utilities and other PAs to earn financial incentives for achieving or exceeding pre-specified peak demand savings targets, which requires reporting of peak demand savings (Relf and Nowak 2018).

Over the last decade, ISO New England (ISO-NE) and PJM have included demand-side resources in their forward capacity markets. These markets help ensure that power systems have sufficient resources to meet future demand for electricity. Energy efficiency is among the eligible demand-side resources. Utilities and others in these regions that bid energy efficiency into the market must quantify the impacts provided by their program portfolio during designated peak periods.[8]

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[6] In 2008, the Pennsylvania legislature passed Act 129, which required each of the seven major electric distribution companies to procure cost-effective energy efficiency and to develop energy efficiency and conservation plans to reduce electricity consumption by a minimum 1% by 2011 (increasing to a total of 3% by 2013) and to reduce peak demand by 4.5% by 2013.

[7] Texas utilities have been reporting peak demand impacts of efficiency programs since 2002. A consistent definition of this metric was part of the PUC evaluation effort and came into effect after 2012. A TRM is a resource that contains energy efficiency measure information used in program planning, implementation, tracking, and reporting and evaluation of impacts associated with the subject measures (Schiller et al. 2017).

[8] See Table B - 2 for ISO-NE and PJM peak periods.

A number of states (e.g., California, Hawaii, Indiana, Maryland, Massachusetts, Michigan, Minnesota, Nevada, New York, Oregon, and Rhode Island) are exploring the impact of increasing adoption of DERs on distribution system planning and operations. In an increasing number of states, including California and New York, this includes competitive procurement processes which are open to DERs (including efficiency) that can potentially defer or avoid distribution system upgrades (Homer et al. 2017; Schwartz and Homer 2018). Resource planning (in vertically integrated states) and transmission planning also are increasingly accounting for DERs (Stanton 2015; Schwartz and Frick 2019). Bidders must demonstrate load reductions during designated peak demand hours identified by the utility to mitigate potential operational or reliability constraints on distribution systems.

In this report, we explore the first-year cost of saving peak demand in nine states (Arizona, Arkansas, California, Colorado, Illinois, Massachusetts, Maryland, New York, and Texas) in recent years (2014-2017). We developed a framework for analyzing peak demand savings across utilities and states and begin to quantify the first-year cost of saving peak demand. Our sample is primarily limited to programs that target customers of investor-owned utilities, with a few exceptions.

This study builds on Berkeley Lab's unique body of work to collect, standardize and analyze data for efficiency programs funded by utility customers and use the information to help decision makers assess the cost performance of programmatic efficiency initiatives across geographic regions, states, market sectors, and program types.[9] We also build on our new line of research on the time-sensitive value of efficiency (Frick and Schwartz, forthcoming; Mims et al. 2017 and 2018).

A related goal of our work is to facilitate increased transparency, consistency and rigor in reporting of costs and impacts of energy efficiency programs.[10] Differences in how utilities and independent system operators (ISOs)/regional transmission organizations (RTOs) define peak demand, as well as the methods used to estimate and report reductions in peak demand due to electricity efficiency programs, pose significant challenges to more transparent and consistent reporting of the cost of saving peak demand and benchmarking these costs. Developing more consistent methods to report peak demand savings will help states, utilities and other program administrators maximize the benefits of efficiency programs and investments, deploy energy efficiency in more strategic ways (e.g., in targeted locations, for particular customer types), determine the peak reduction potential from efficiency programs, and assess relative costs of achieving peak savings from efficiency compared to alternative resource options.

[9] In previous reports, we quantified the program administrator cost of saving energy for electricity and natural gas efficiency programs implemented between 2009 and 2011 (Billingsley et al. 2014), the total cost of saving electricity (including participant costs) for program years 2009-2013 (Hoffman et al. 2015), trends in the program administrator cost of saving electricity over time (Hoffman et al. 2017), and the program administrator and total cost of saving electricity for 41 states through 2015 (Hoffman et al. 2018).

[10] We have developed methods (e.g., program typology, standardized definitions for program data) and tools to help facilitate reporting. See emp.lbl.gov/projects/what-it-costs-save-energy.

1.1 Report Objectives and Roadmap

In this study, we explore the following questions and issues:

- To what extent are utilities and other program administrators reporting information on the peak demand impacts of their electricity efficiency programs?
- How do program administrators define peak demand and calculate peak demand savings for their electricity efficiency programs?
- For the nine selected states, what are the cost of saving electricity and first-year cost of saving peak demand at the portfolio level and for selected types of programs?

The remainder of this report is organized as follows:

- *Chapter 2* describes our approach to compile and analyze efficiency program data that includes information on program costs and peak demand savings as well as defining the metrics used to summarize our initial results. We also discuss the range in approaches that states use to define peak demand and peak demand reductions.
- *Chapter 3* summarizes the results of this study — program administrator (utility) cost of saving electricity and first-year cost of saving peak demand for nine states at the portfolio level and for selected program types.
- *Chapter 4* discusses issues related to transparent and consistent reporting of peak demand impacts, including suggestions for state policymakers and program administrators to consider.
- *Appendices* provide additional information.

2. Data Collection and Analysis Approach

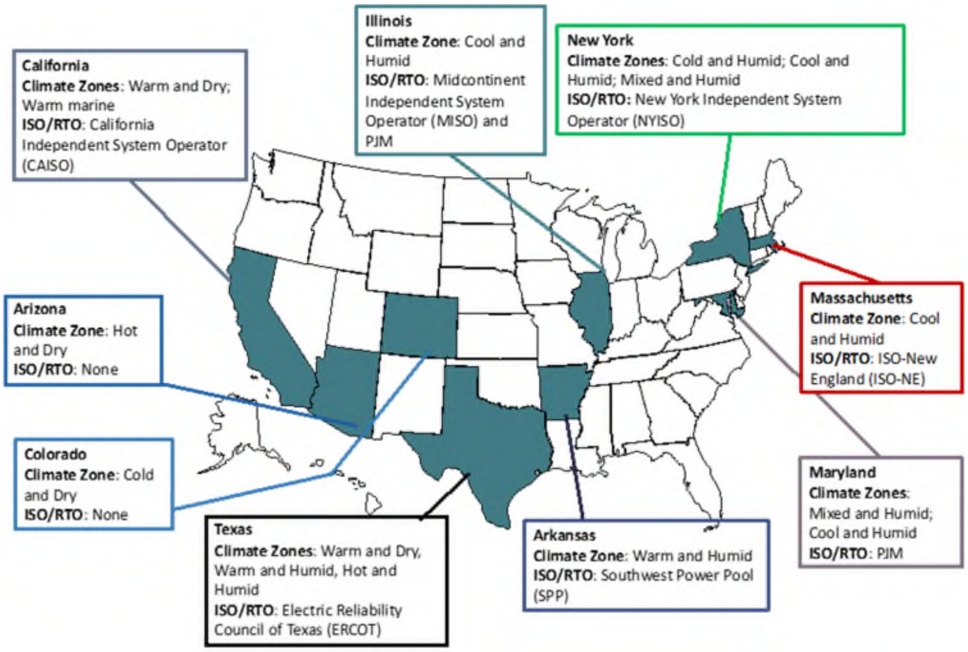
This chapter discusses the process used to identify and select states included in this study. We also describe the approach we used to compile and analyze program data and highlight several data reporting and consistency issues. Finally, we describe our metrics for summarizing results at the portfolio and program level: the levelized CSE and the first-year CSPD.

2.1 Sample Selection and Program Data Collection

We identified and selected states for this study based on policy requirements, data availability, geographic diversity, and utility spending on efficiency programs. We first identified states that have a policy requirement for investor-owned utilities to achieve peak demand reductions,[11] or where utilities record demand reductions in efficiency program regulatory filings. From these states, we chose a sample of nine states that are diverse in terms of climate zones and geography, which we defined as representation from several ISO/RTOs (see Figure 2-1). We prioritized data gathering from states where utilities were members of ISO/RTOs because some ISOs (e.g., PJM, ISO-NE) allow utilities (and load aggregators) to participate in forward capacity markets and bid in program savings during defined peak periods. Where possible, we included states with significant spending on energy efficiency (e.g., California, Illinois, Massachusetts, and New York).

[11] Colorado, Illinois, Maryland, and Texas have peak demand reduction targets and are included in our sample of states; other states with peak demand reduction requirements include Ohio and Pennsylvania. Maryland had a peak demand reduction goal of 15% per capita by 2015 from a 2007 baseline. While the state no longer has a goal for demand reduction (only energy savings), the Public Service Commission directed utilities to maintain achieved peak demand reductions.

Figure 2-1. States, climate zones, and ISO/RTO regions included in this study[12]



With few exceptions, our data collection relied on 2014-2017 annual reports filed by utilities (and other program administrators) with state public utility commissions.[13] Our sample for this study includes 36 utilities and more than 2,900 program years of data. Approximately two-thirds of the program records (or program years) include peak demand impacts.[14] Data fields for each program year include the program name, spending information (e.g., actual expenditures), peak demand savings, and annual and lifetime gross and net energy savings, where available. Table A - 1 in Appendix A provides program years used in the analysis by state. Spending on electricity efficiency programs in these nine states represents about 43% to 49% of national spending during the 2014-2016 period.[15]

We standardized, validated and analyzed the efficiency program data consistent with practices used in prior Berkeley Lab studies (Billingsley et al. 2014; Hoffman et al. 2015; Hoffman et al. 2017; Hoffman et al. 2018). We adopted several new decision rules for reporting peak demand impacts for several states.[16]

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[12] See ASHRAE (2017). We do not include data from four climate zones in our program analysis graphs (Section 3.2.1-3.2.7) due to small sample size. Data from all climate zones was used in determining first-year CSPD and levelized CSE averages and medians (Table 3-2).

[13] Where we obtained data from other sources (e.g., state database queries in New York), we made spot checks against utility and other program administrator filings to ensure the fidelity of the database values. We use data reported by utilities and other program administrators; we do not independently determine or validate reported costs and savings.

[14] In reporting program-level savings, most utilities include some programs that incur costs but do not produce savings.

[15] Our estimates of national spending on electricity efficiency programs come from the ACEEE Scorecard for 2014 and 2015 and Berkeley Lab analysis in 2016 (Goldman et al. 2018).

[16] See Table A - 1 for detail.

2.2 Defining Peak Demand and Peak Demand Impacts

A major challenge in this study was assessing how state regulators/policymakers and utilities define and use terms such as peak demand, peak demand reduction and coincident peak demand reduction in their energy efficiency programs. We conducted an extensive literature review that included demand-side management (DSM) filings; TRMs; evaluation, measurement and verification (EM&V) protocols and reports; utility tariffs; and ISO/RTO guidance to collect definitions of peak demand associated with efficiency programs, peak demand periods, and calculations for demand reduction impacts from energy efficiency.

Table B - 1 in Appendix B lists approaches identified in the U.S. Department of Energy's (DOE's) Uniform Methods Project for estimating peak demand reductions for electricity efficiency programs. Table B - 2 lists the definition of peak demand used by a variety of organizations and sources, and definitions used to calculate peak demand reductions by 17 organizations in the states covered by this study.

We also summarize the peak periods (months and weekday hours) as well the number of days and total number of hours in the peak period for utilities in our nine-state sample (Table B - 3). We observe significant differences in how states define peak period hours for program planning and evaluation purposes, ranging from one hour in Texas to 640 hours in Arizona. The summer peak period encompasses May through October in Arizona; June through September in California, Arkansas and Texas; and June through August in Colorado, Illinois, Maryland, Massachusetts, and New York. While electricity efficiency programs also provide winter peak demand savings, these states experience their highest demand during summer. The focus of this exploratory study is on first-year cost of saving peak demand during summer.

Utilities with service territories covered by ISO-NE generally use the same definitions of hours that are included in the ISO's peak period because most utilities bid their efficiency resources into the forward capacity market.[17] In contrast, in Arkansas, utilities provide demand savings that are identified as non-coincident peak, while SPP provides definitions of actual and forecasted peak demand (Table B - 3).

Many efficiency programs include measures whose savings are sensitive to climate. Thus, in this study, we explore the extent to which the first-year CSPD may be influenced by climate. For example, all else equal, electricity savings should be greater for high-efficiency air conditioners installed in a hot, humid climate (e.g., Texas) than in a cool, humid climate (upstate New York, Illinois) due to more hours of operation. We collected information on cooling and heating degree days in nine climate zones as defined by ASHRAE and classified our program administrators into climate zones based on their service territory (Figure 2-1 and Table B - 4) (ASHRAE 2017; Briggs, Lucas and Taylor 2003).

[17] In ISO-New England, the summer on-peak period is defined as weekday hours ending 1400 through 1700 during June through August, while the winter on-peak period is defined as weekday hours ending 1800 through 1900 during December and January. In PJM, the summer on-peak period is defined as weekday hours between the hour ending 1500 and the hour ending 1800 during June through August, and winter on-peak period is defined as weekday hours ending at 800 and 900 and between 1900 and 2000.

Our review of the approaches that utilities and ISOs/RTOs use to define and report peak periods and methods they used to estimate savings during peak periods revealed a number of issues that complicate efforts for comparative analysis of the first-year CSPD. These issues can be grouped into four categories:

1. **Missing data on peak period savings.** Some utilities in our sample did not record peak demand savings for all efficiency programs that they delivered. It is not clear if the programs do not produce peak demand savings or if the savings are simply not being recorded.
2. **Different definitions of peak periods.** In our sample, the number of hours included in the peak period ranged from one hour to 650 hours. This was a larger range than we anticipated.
3. **Inconsistent reporting and varying methods to calculate peak demand reductions.** Compiling information on how utilities define peak period savings was challenging because the information was not readily available in annual reports to state public utility commission. Moreover, utilities and states may use different methods to calculate peak demand reductions achieved by efficiency programs.
4. **Coincidence factors.**[18] Coincidence factors are often used to quantify the peak demand savings from a measure or program that occur at the same time as the electric system peak. While coincidence factors may be described in TRMs that utilities use in program planning, implementation, tracking, and evaluation of efficiency measures, it was outside the scope of this study to verify the original sources or accuracy of the factors used.

2.3 Cost of Saving Electricity and First-Year Cost of Saving Peak Demand: Definition and Inputs

In this study, the key metrics of interest are the levelized program administrator (utility) CSE and first-year program administrator (utility) CSPD. The CSE is expressed in dollars per kWh of electricity savings, and the first-year CSPD is expressed in dollars per kW. These metrics measure activities from a utility's perspective. They are useful for comparing relative costs of various types of efficiency programs and comparing efficiency options to other demand and supply choices for serving electricity needs. This section provides additional information on key assumptions and input variables used in calculating these values.

[18] Coincidence factors may be defined as "the fractions of the connected (or rated) load (based on actual lighting watts, motor nameplate horsepower and efficiency, AC rated capacity and efficiency, etc.) reductions that actually occur during seasonal demand windows. They are the ratio of the demand reductions during the coincident windows to the maximum connected load reductions. Under this definition other issues such as diversity and load factor are automatically accounted for, and only the coincidence factor will be necessary to determine coincident demand reductions from readily observable equipment nameplate (rated) information. Coincident demand reduction will simply be the product of the coincidence factor and the connected equipment load kW reduction" (RLW 2007). For other definitions, see Mims, Eckman, Goldman (2017).

The levelized CSE is the cost of achieving electricity savings over the economic lifetime of the actions taken as a result of a program, amortized over that lifetime, and discounted back to the year in which the costs are paid and the actions taken. The CSE accounts for expenditures in planning, administering, designing, and implementing programs and providing incentives to market allies and end users to take actions that result in energy savings, as well as the costs of verifying those savings.[19] Equation 1 shows the calculation for the levelized CSE.

Equation 1:

Program Administrator Levelized Cost of Saving Electricity =

$$\frac{\textit{Capital Recovery Factor * (Program Administrator Costs)}}{\textit{Annual Electricity Savings (in kWh)}}$$

where the Capital Recovery Factor (CRF) is:

$$CRF = \frac{r\left(1+r\right)^{N}}{\left(1+r\right)^{N}-1}.$$

and

r = the discount rate

N = estimated program lifetime in years and calculated as the savings-weighted lifetime of measures or actions installed by participating customers in a program

We used our standard approach to calculating the CSE to provide readers with a reference point when introducing the new first-year CSPD metric. We used a 6% real discount rate as an approximation of the weighted-average cost of capital for an investor-owned electric utility.[20] We adjusted to 2017 dollars program spending that was reported in nominal dollars. We used gross savings to calculate the program administrator CSE and first-year CSPD, primarily because net savings are not universally reported or uniformly defined.[21] As in previous Berkeley Lab CSE reports, when we report the CSE at the portfolio level, we included costs of cross-cutting programs (e.g., spending in such areas as market research and planning, and programs that reported costs but not savings).

[19] We included EM&V costs at the portfolio-level and for specific programs (if reported at the program level). Some ancillary costs associated with investments in energy efficiency are not included because they are either not reported or not included in annual reports to public utility commissions. These costs include performance incentives for the utility or other program administrator, the time and transaction costs incurred by participants (e.g., analyzing potential efficiency investments, getting the work done), and tax credits.

[20] We use a real discount rate because inflation already is accounted for in the use of constant dollars (2017$). Our real discount rate is a proxy for a nominal rate in the range of 7.5% to 9%, typical values for a utility weighted-average cost of capital (WACC). A utility WACC is the average of the cost of payments on the utility's debt (bonds) and its equity (stock), weighted by the relative share of each in the utility's funds available for capital investment. The utility WACC is often used by investor-owned utilities in their economic screening of efficiency programs.

[21] In addition, inconsistencies in defining and estimating net savings add more uncertainty to those already embedded in estimates of energy savings and peak demand impacts. See Billingsley et al. (2014) and Hoffman et al. (2018) for a more in-depth discussion of our rationale for using gross savings estimates.

Equation 2 shows the calculation for the first-year CSPD. We calculate the first-year CSPD in constant 2017 dollars per kW saved. The first-year CSPD for efficiency is the cost of achieving summer peak demand savings in the first year that the efficiency measures are implemented in the program. We use first-year program costs[22] and peak demand savings to simplify this first-ever analysis.[23] In future studies, we may quantify and calculate the CSPD over the expected lifetime of the peak demand savings (i.e., a levelized CSPD).[24] We use *summer* peak demand savings values for this study because all utilities and program administrators included in the analysis reported it. A limited set of utilities and program administrators provide winter peak demand savings values.[25]

Equation 2:

$$\textbf{\textit{First-Year Program Administrator Cost of Saving Peak Demand}} = \frac{\textit{Program Administrator Costs (\$)}}{\textit{Summer Peak Demand Savings (kW)}}$$

In calculating the first-year CSPD results at the portfolio level, we excluded programs that reported costs, but not peak demand savings, or programs that are cross-cutting. Approximately 5% of the programs in our sample had data on energy savings and program costs, but did not report peak demand savings. In these cases, it is not clear whether the program did not achieve peak demand savings or if the utility did not report peak demand savings. Thus, in calculating the first-year CSPD at the portfolio level, we included only those programs that reported both costs and peak demand savings.[26]

[22] Program costs include expenditures in planning, administering, designing and implementing programs and providing incentives to market allies and end users.
[23] In Hoffman et al. 2018, we note that measure lifetimes are essential to calculating the levelized cost of saving electricity, although only 27% of program administrators reported measure lifetime or lifetime savings, or both. This data limitation means that we had to impute program average measure lifetimes for over half of the program years based on average values from programs where utilities reported this information.
[24] In some cases, lifetime value of peak demand savings is not fully captured, even in those RTO and ISO markets that allow energy efficiency to participate as a capacity resource. For example, PJM allows a maximum measure lifetime of only four years.
[25] We recorded winter peak demand reductions in our database, but excluded these impacts from this analysis.
[26] In future versions of this analysis, and as we gather more data on peak demand reductions from efficiency, we may include all costs in our calculation of the CSPD at the portfolio level.

3. Results: First-Year Program Administrator Cost of Saving Peak Demand

This chapter summarizes the results of our study on the cost of saving peak demand in nine representative states. We present CSE and first-year CSPD results at the state level and for specific types of programs.

We include the CSE in this analysis to provide a foundation for readers that is grounded in Berkeley Lab's past research on the cost of saving electricity. We display first-year CSPD results for specific types of programs by climate zone in order to assess the extent to which the first-year CSPD varies in programs with measures that are weather-sensitive. Given the differences in approaches that states use in calculating and reporting peak demand savings, we also show the first-year CSPD for several types of programs and categorize results by the approach utilities use to define the peak period.

We report electricity savings-weighted average and median values for CSE and first-year CSPD. To calculate the savings-weighted averages, we assign the cost performance of each program more or less value based on the annual electricity savings. That means programs (and program administrators) with higher savings have greater influence on the average CSE and first-year CSPD than programs with lower savings.

3.1 First-Year Cost of Saving Peak Demand: Selected States

Energy efficiency programs yield both energy and peak demand savings, avoiding energy and capacity costs. Table 3-1 shows the savings-weighted average for the CSE and first-year CSPD for the 36 utilities and other program administrators in our nine-state sample between 2014 and 2017, in increasing order of first-year CSPD.

Table 3-1. First-year cost of saving peak demand and levelized cost of saving electricity by state (2014–2017)

State	Savings-Weighted First-Year PA CSPD (2017$/kW)	Savings-Weighted PA CSE (2017$/kWh)
Arizona	568	0.013
Illinois	646	0.020
Texas	732	0.021
Colorado	963	0.020
Arkansas	1,208	0.030
California	1,555	0.036
Maryland	1,651	0.036
New York	1,836	0.025
Massachusetts	2,353	0.039
All Nine States (average)	1,483	0.029

The CSE values range from $0.013/kWh to $0.039/kWh, while the first-year CSPD values range from ~$570/kW to ~$2,350/kW. The savings-weighted average CSE is $0.029/kWh, and the first-year CSPD is $1,483/kW.[27] Not surprisingly, the first-year CSPD tends to be lower in states with climates that are hot and humid (Texas) or hot and dry (Arizona), although in Illinois utilities report a low first-year CSPD ($600/kW) in a cool and humid climate.

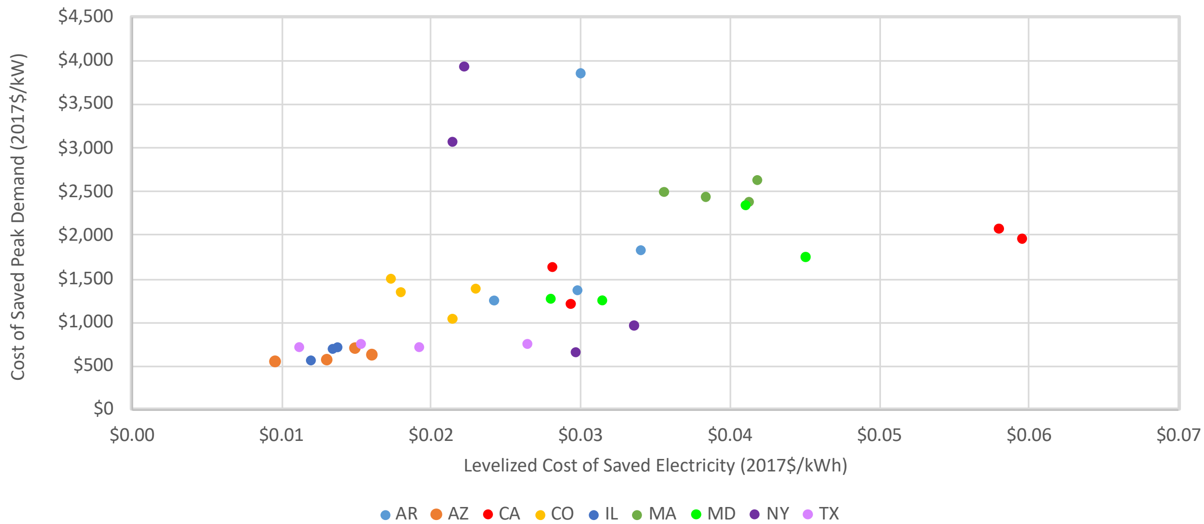
Our results suggest that lower values for first-year CSPD in some states are driven primarily by the relative cost of efficiency programs (see the CSE values to calibrate) and the peak demand savings that are achieved per dollar invested, which tend to be greater in hot climates. In general, our results suggest a correlation between the CSE and first-year CSPD values in each state — states with higher CSE values (California, Maryland, Massachusetts) tend to have higher first-year CSPD values, which range from $1,555/kW to $2,353/kW, and vice versa. The CSE values for New York are mid-range among the nine states ($0.025/kWh), while first-year CSPD values are on the higher side ($1,836/kW). This result is more challenging to interpret. It may be attributable to the mix of programs offered by program administrators (utilities and the New York State Energy Research & Development Authority — NYSERDA) and also reflects that NYSERDA did not report peak demand savings in 2016 and 2017 for most of its efficiency programs.

Figure 3-1 shows a plot of the energy savings-weighted average values for CSE and first-year CSPD for each program year, color-coded by state, with three to four years of program data for each. The annual CSE and first-year CSPD values are tightly clustered for several states (Arizona, Colorado, Massachusetts

[27] The CSE value is slightly higher than our most recent cost of saving electricity report (Hoffman et al. 2018). Because our sample for this study is composed of states with relatively mature energy efficiency programs, significant energy savings, and more comprehensive reporting requirements, this result is to be expected.

and Texas). That is a logical result if program budgets are relatively stable, program administrators are experienced or the mix of programs does not change dramatically.

Figure 3-1. First-year cost of saving peak demand and levelized cost of saving electricity by state (2014-2017)



The results in New York appear to be an exception. We believe that these results highlight some of the changes in efficiency programs that occurred during the New York Reforming Energy Vision transition period. For example, NYSERDA reported electricity savings but did not report peak demand savings for most of its programs in 2016 and 2017. Thus, the first-year CSPD values in 2016 and 2017 (< $1,000 kW) primarily reflect programs administered by the electric utilities in New York.

3.2 First-Year Cost of Saving Peak Demand: Selected Program Types

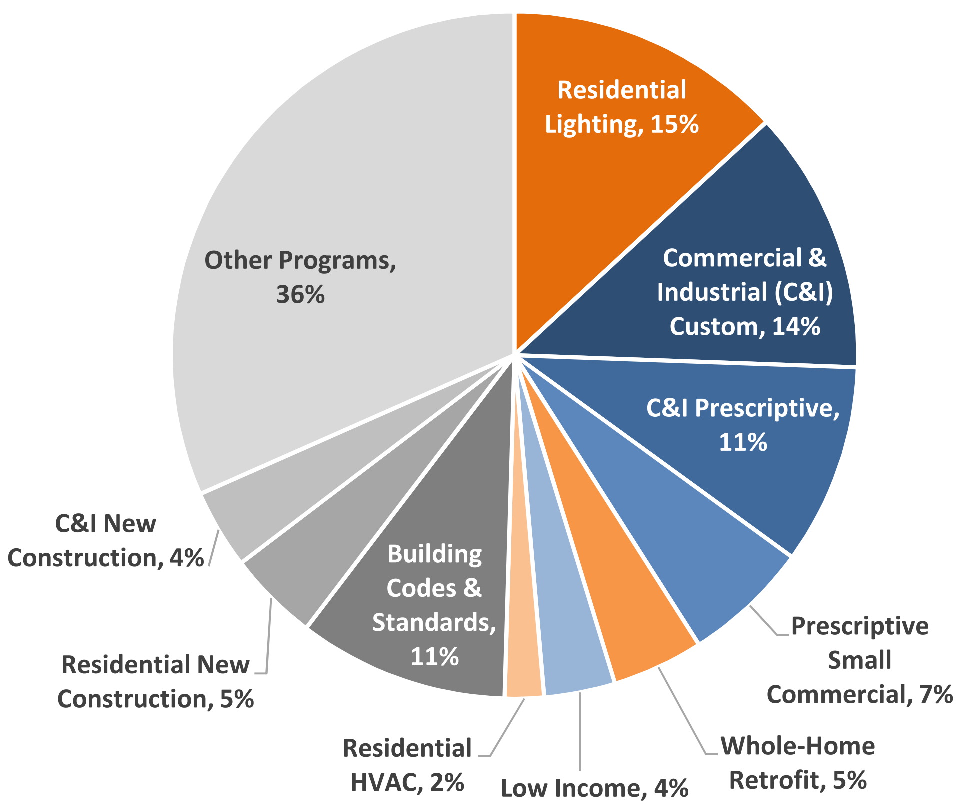
This section summarizes results for selected types of efficiency programs. Table 3-2 provides a high-level summary of results for seven programs: residential lighting, prescriptive rebates for medium and large C&I customers, programs targeted at small commercial customers, residential HVAC, whole-home retrofit programs, custom rebate programs for large C&I customers, and low-income programs. These seven programs were selected because they are often among the largest programs offered by program administrators and account for a significant share of peak demand savings.

Table 3-2. First-year cost of saving peak demand and levelized cost of saving electricity for selected types of programs (2014-2017)

Program Type	Savings-Weighted Average First-Year CSPD (2017$/kW)	Median First-Year CSPD (2017$/kW)	Savings-Weighted Average CSE (2017$/kWh)	Median CSE (2017$/kWh)
Residential Lighting	733	738	0.013	0.013
C&I Prescriptive Rebate	1,331	1,332	0.026	0.027
C&I Small Commercial	2,071	1,993	0.050	0.042
Residential HVAC	2,331	2,202	0.078	0.094
Whole-Home Retrofit	2,543	1,960	0.056	0.072
C&I Custom Rebate	3,339	1,784	0.023	0.029
Low Income	5,751	2,099	0.135	0.091

Figure 3-2 shows the share of peak demand savings for various types of programs studied in the nine states between 2014 and 2017. The area of Figure 3-2 that is in color represents the programs we considered in this study, which accounts for 58% of peak demand savings for the 36 utilities in our study between 2014 and 2017.

Figure 3-2. Peak demand savings by type of efficiency program in nine states (2014-2017)



For each program, we show the savings-weighted average and median values for levelized CSE and first-year CSPD. We focus primarily in this report on the first-year CSPD results. Similar to CSE results, residential lighting programs are the lowest cost resource for peak demand savings (~$735/kW), followed by prescriptive rebates that target medium and large C&I customers ($1,331/kW). Several programs (small C&I rebate programs, residential HVAC, and whole home retrofit) have comparable program savings-weighted average or median values, ranging from about $2,071 to 2,543/kW.

Results are more difficult to explain for C&I custom rebate programs, with the savings-weighted average first-year CSPD ($3,339/kW) almost 50% higher than the median first-year CSPD ($1,784/kW). These programs are heterogeneous, spanning HVAC equipment and controls for commercial customers to process improvements for industrial customers. The diverse mix of measures and different peak demand savings profiles may explain why we observe higher values and more variance in first-year CSPD results across utilities.[28]

Results for low-income programs are also more difficult to interpret, as there are large differences between the first-year CSPD median values of $2,099/kW and savings-weighted average of $5,751/kW. This difference can be explained in part by the difference between the savings-weighted average CSE ($0.09/kWh) and median CSE ($0.13/kWh). Another explanation may be that California utilities administer large low-income programs with significant spending that yields moderate energy and peak demand savings, which tends to increase the first-year savings-weighted average CSPD value.

The levelized CSPD is much lower than the first-year CSPD because the entire program life is considered in the calculation. The text box below shows three illustrative levelized CSPD program examples.

[28] Another factor to consider is programs that rely on ex post savings estimates (rather than ex ante). The level of rigor associated with C&I custom rebate programs varies significantly, ranging from simple engineering reviews to more extensive monitoring approaches. More rigorous M&V approaches often result in lower realization rates (close to 0.5 to 0.7) compared to realization rates in engineering reviews or ex ante savings approaches. This can create more variability in gross savings estimates across programs.

What about the levelized cost of saving peak demand?

We calculated levelized CSPD for three types of programs to illustrate the impact of spreading program costs over the effective useful lifetime of electricity efficiency measures:

- Residential lighting: $94/kW
- Residential HVAC: $249/kW
- Commercial & industrial prescriptive rebate: $148/kW

These results and other findings in this initial study of the CSPD indicate that electricity efficiency programs appear to be a relatively low-cost way for utilities to meet peak demand, compared to the capital cost of other resources (Lazard 2018; EIA 2019).* However, many energy efficiency technologies (e.g., more efficient light bulbs) are "passive" and are not dispatchable. In such cases, efficiency resources do not provide the same services as a natural gas peaking turbine, making comparisons between resources complex. At the same time, our results suggest that some electricity efficiency programs that reduce peak demand merit strong consideration by utilities and ISOs/RTOs. Further, "active" efficiency measures (e.g., lighting controls) enable active management of efficiency resources, offering additional grid services. See the U.S. Department of Energy's Grid-Interactive Efficient Buildings initiative: www.energy.gov/eere/buildings/grid-interactive-efficient-buildings.

* See Appendix C for details.

We also explored factors that may account for some of the observed variation in efficiency program first-year CSPD values and to test our hypothesis that programs with weather-dependent measures tend to have a lower first-year CSPD in more extreme climates. Figure 3-3 through Figure 3-9 display these results, with the levelized CSE on the x-axis and first-year CSPD on the y-axis. Data points represent a program year of results for that type of program for utilities and other program administrators in our sample (n = number of program years in that climate zone for the program type). The data points are color-coded by climate zone, for five of the zones in our sample.[29] Typically there are three to four data points (years of program data) for each program administrator. We include linear regressions, or "best fit" lines, for data points. Our objective is to highlight the central tendency for program values in a climate zone.

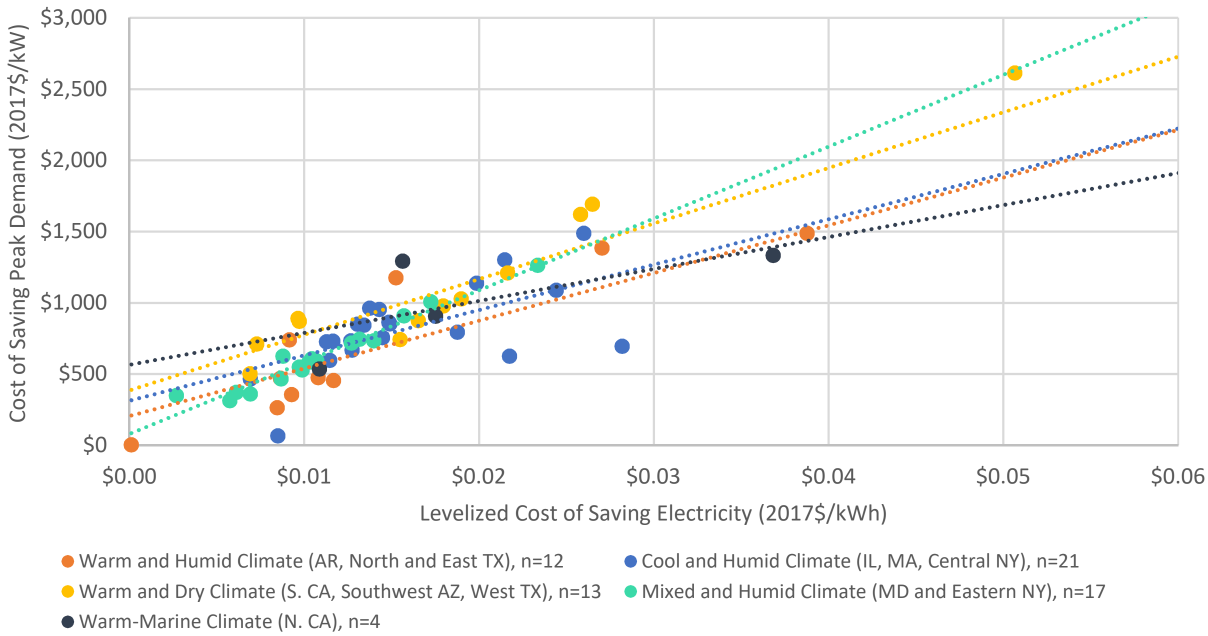
3.2.1 Residential Lighting Programs: First-Year Cost of Saving Peak Demand

Figure 3-3 shows CSE and first-year CSPD results for residential lighting programs for program administrators for five climate zones. More than 80% of these programs have first-year savings-weighted CSPD values less than $1,000/kW (and CSE of less than $0.02/kWh). In our sample, residential lighting programs are the lowest cost resource for peak demand savings. Not surprisingly, these results

[29] We do not include data from four climate zones in our program analysis graphs (Section 3.2.1-3.2.7) due to small sample size. Data from all climate zones was used in determining first-year CSPD and CSE averages and medians (Table 3-2)

occur somewhat independently of climate zone. For example, program administrators in a mixed and humid climate (Maryland, New York) reported some of the lowest first-year CSPD values ($300-$750/kW), even though there are fewer cooling degree days than warm and humid climate zones (e.g., parts of Texas, Arkansas).

Figure 3-3. Residential lighting programs: first-year cost of saving peak demand

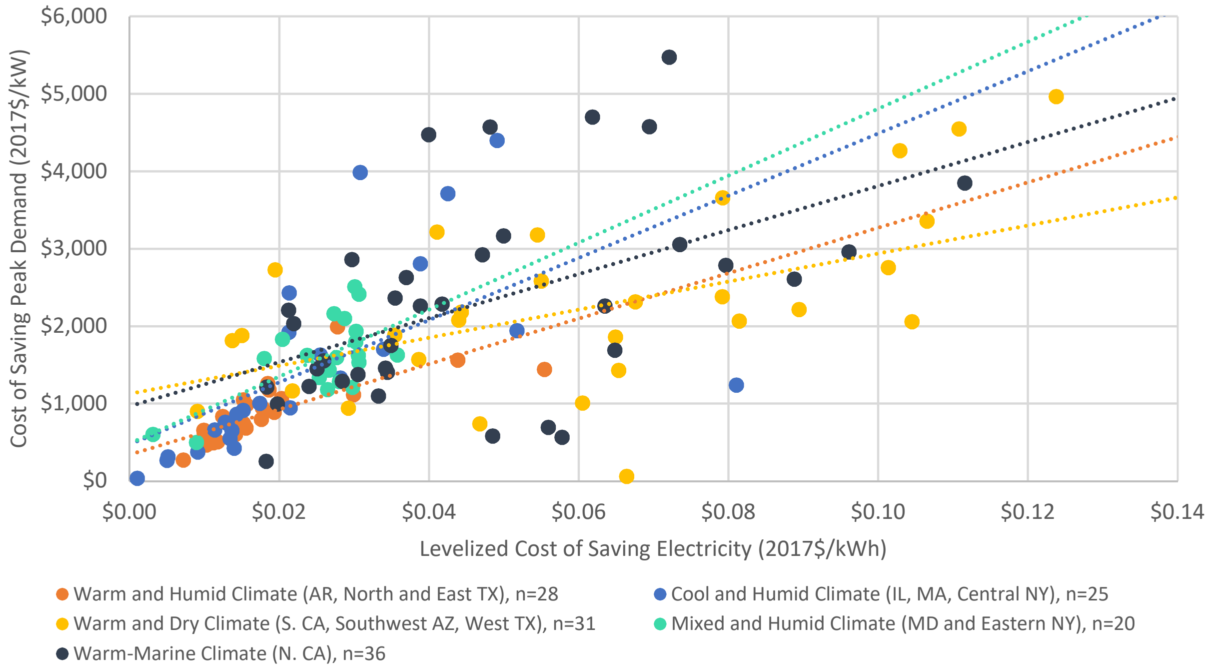


3.2.2 C&I Prescriptive Rebate Programs: First-Year Cost of Saving Peak Demand

The savings-weighted average and first-year median CSPD values for C&I prescriptive rebate programs are both about $1,300/kW. In aggregate, C&I prescriptive programs account for about 11% of total peak demand savings for program administrators in the nine states, and they have a heterogeneous measure mix, unlike residential lighting programs.[30] Figure 3-4 shows the first-year CSPD and CSE results for C&I prescriptive rebate programs for five climate zones. The measure mix results in wide variation in peak demand savings and first-year as compared to residential lighting. In contrast to programs that target small commercial customers (Figure 3-5) we see a greater spread in first-year CSPD values, which is particularly noticeable in warm and dry climates (Southern California and Arizona) and warm marine climates (Northern California). About two-thirds of the C&I prescriptive programs have first-year CSPD values that are ≤ $2,000/kW.

[30] Lighting savings typically account for the majority of C&I prescriptive program savings; however, in states with the most mature programs (California, New England), non-lighting measures account for a significant share of total savings, often increasing over time.

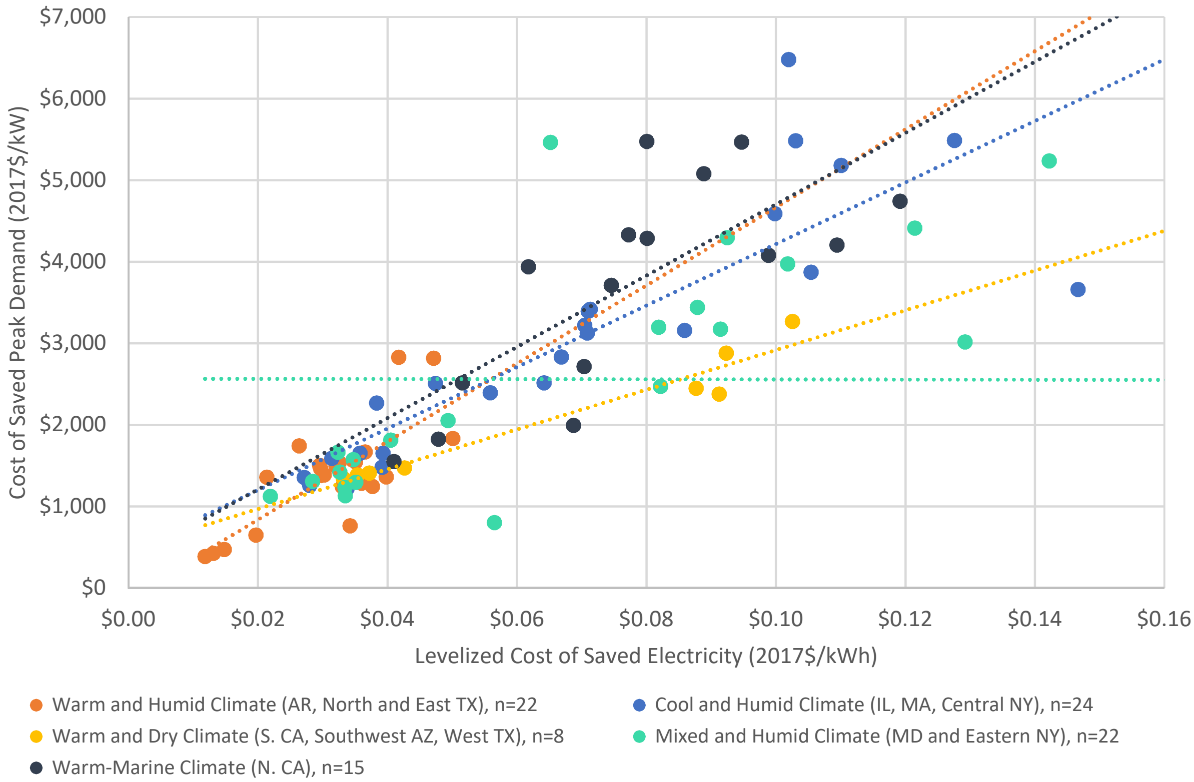
Figure 3-4. C&I prescriptive rebate programs: first-year cost of saving peak demand



3.2.3 Small Commercial Programs: First-Year Cost of Saving Peak Demand

Figure 3-5 shows first-year CSPD and CSE results for efficiency programs that target small commercial customers in five climate zones. Lighting typically accounts for ~85% of the savings for these programs, and often the program implementation strategy includes direct installation of lighting systems and measures. The first-year savings-weighted average CSPD for small commercial market programs is ~$2,070/kW. In contrast to residential lighting (Figure 3-3), we do not observe a strong clustering of programs with low first-year CSPD values. Locations where first-year CSPD values are high (> $3,500/kW), such as Maryland, Massachusetts, and Northern California, also tend to have higher CSE values.

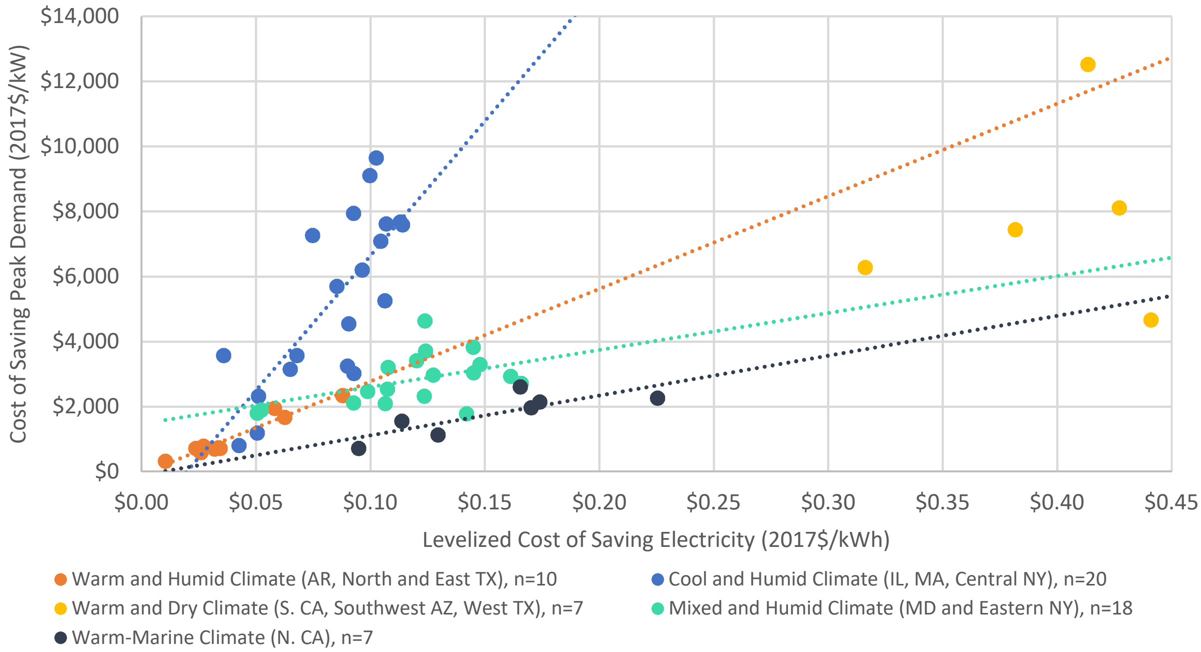
Figure 3-5. Small commercial programs: first-year cost of saving peak demand



3.2.4 Residential HVAC Programs: First-Year Cost of Saving Peak Demand

HVAC programs illustrate first-year CSPD values with weather-sensitive measures in the residential market sector. Figure 3-6 shows first-year CSPD and CSE results for program administrators in five climate zones. Residential HVAC programs often have high coincidence factors but still tend to be relatively expensive (first-year median CSPD of $2,200/kW). The first-year CSPD tends to be much higher in cool and humid climates such as Illinois, Massachusetts, central and western New York ($3,000-$10,000/kW), and Southern California ($5,000-$12,000/kW) compared to warm and humid climates such as Arizona and parts of Texas (< $2,000/kW) and northern California ($2,000/kW) and mixed and humid climates such as Maryland and most of New York ($2,000-$4,000/kW). Our first-year CSPD results suggest the influence of both program design (e.g., relative cost and success in the market, mix of measures, maturity) and climate severity (e.g., higher savings potential to reduce cooling loads).

Figure 3-6. Residential HVAC programs: first-year cost of saving peak demand[31]



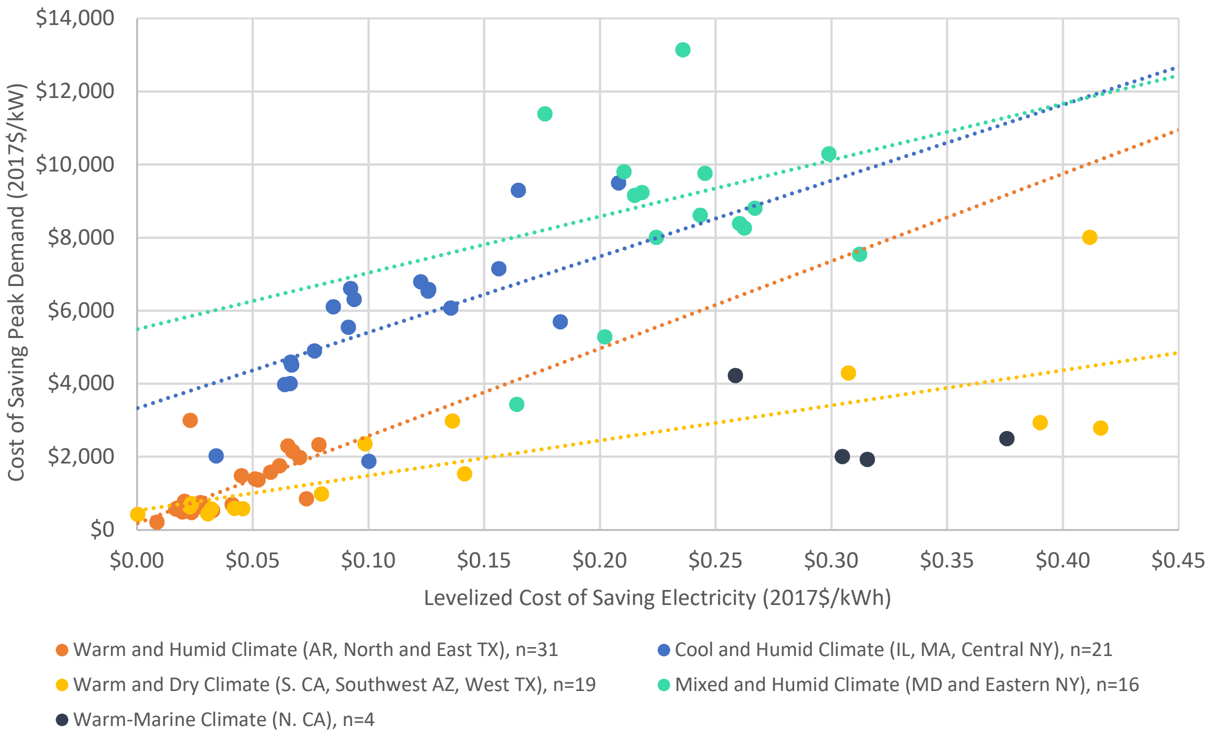
3.2.5 Whole-Home Retrofit Programs: First-Year Cost of Saving Peak Demand

Figure 3-7 shows CSE and first-year CSPD results for whole-home retrofit programs for program administrators in five climate zones. The wide scatter in CSE values ($0.02/kWh to $0.40/kWh) may suggest that program administrators are trying diverse program design strategies in this category of programs (with cost implications). First-year median CSPD values ($2,000-$2,500/kW) tend to be more expensive than residential lighting programs (~$1,000/kW). However, first-year savings-weighted CSPD results are also highly variable, ranging from $500-$1,800/kW for program administrators located in warm and humid climates (Arkansas, parts of Texas) and warm and dry climates (Arizona). Many of the programs use designs that are linked to Home Performance with ENERGY STAR[32] or target projects with fewer measures. On the high end, first-year CSPD values are greater than $6,000/kW in cool and humid climates (Illinois, Massachusetts) and mixed and humid climates (Maryland, parts of New York). Some of these programs (California, Maryland, and Massachusetts) rely on full-featured Home Performance with ENERGY STAR designs.

[31] Number of program years (n) is for each climate zone for residential HVAC programs. Values for CSE for several residential HVAC programs were outliers and are excluded.

[32] See www.energystar.gov/index.cfm?c=home_improvement.hpwes_sponsors_about.

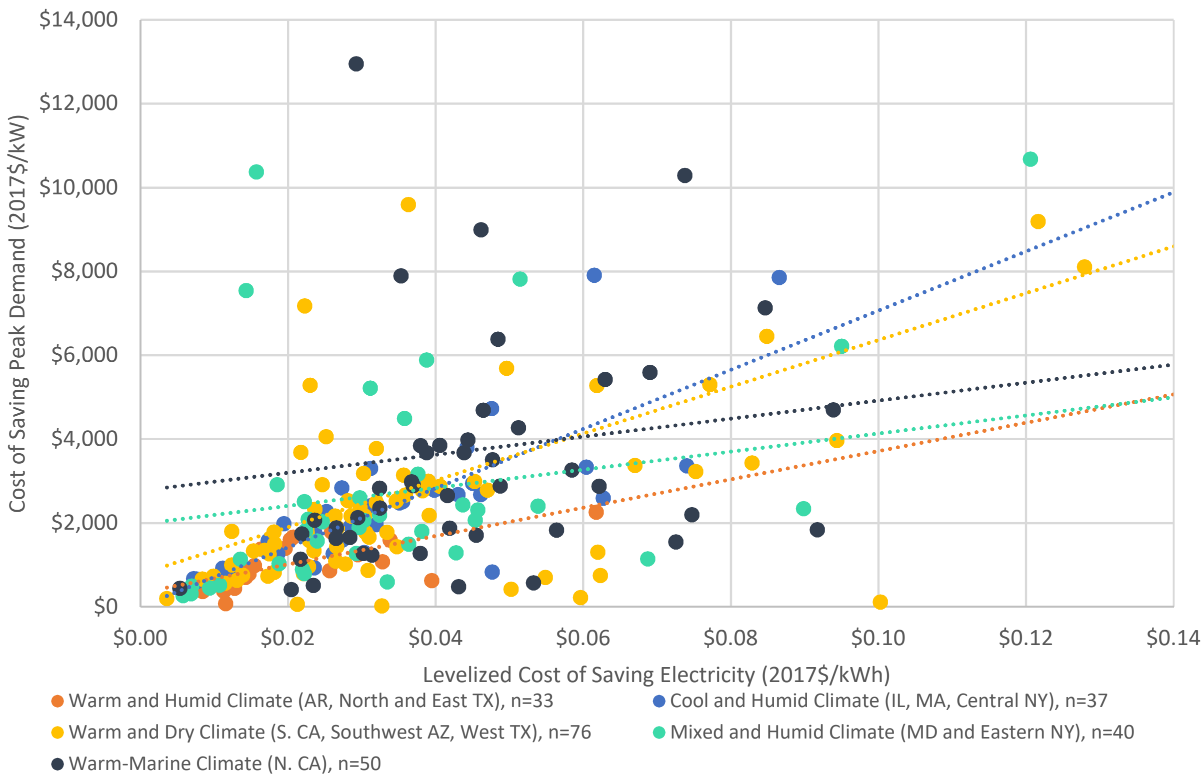
Figure 3-7. Whole-home retrofit programs: first-year cost of saving peak demand



3.2.6 C&I Custom Programs: First-Year Cost of Saving Peak Demand

Figure 3-8 shows first-year CSPD and CSE results for C&I custom programs. We offer several observations. First, we have a large sample of programs of this type (~240 program years), which illustrates their relative importance in energy efficiency portfolios and that some utilities offer custom programs whose design may vary somewhat by target market sector (e.g., industrial, agricultural, commercial) and strategy (e.g., retrocommissioning, custom rebate). Second, about 28% of the programs have first-year CSPD values ≤ $1,000/kW, and 27% have first-year CSPD values between $1,000/kW and $2,000/kW. Many programs with low first-year CSPD values target agricultural customers or industrial process retrofits. Programs in warm and humid climates (Arkansas, Texas); warm, marine climates (Northern California); and warm and dry climates (Arizona, Texas) have first-year CSPD values concentrated in the low to medium range. Third, first-year CSPD values for custom C&I programs that focus on retrocommissioning (e.g., in California, Maryland, Illinois, and Texas) are quite variable.

Figure 3-8. C&I custom programs: first-year cost of saving peak demand

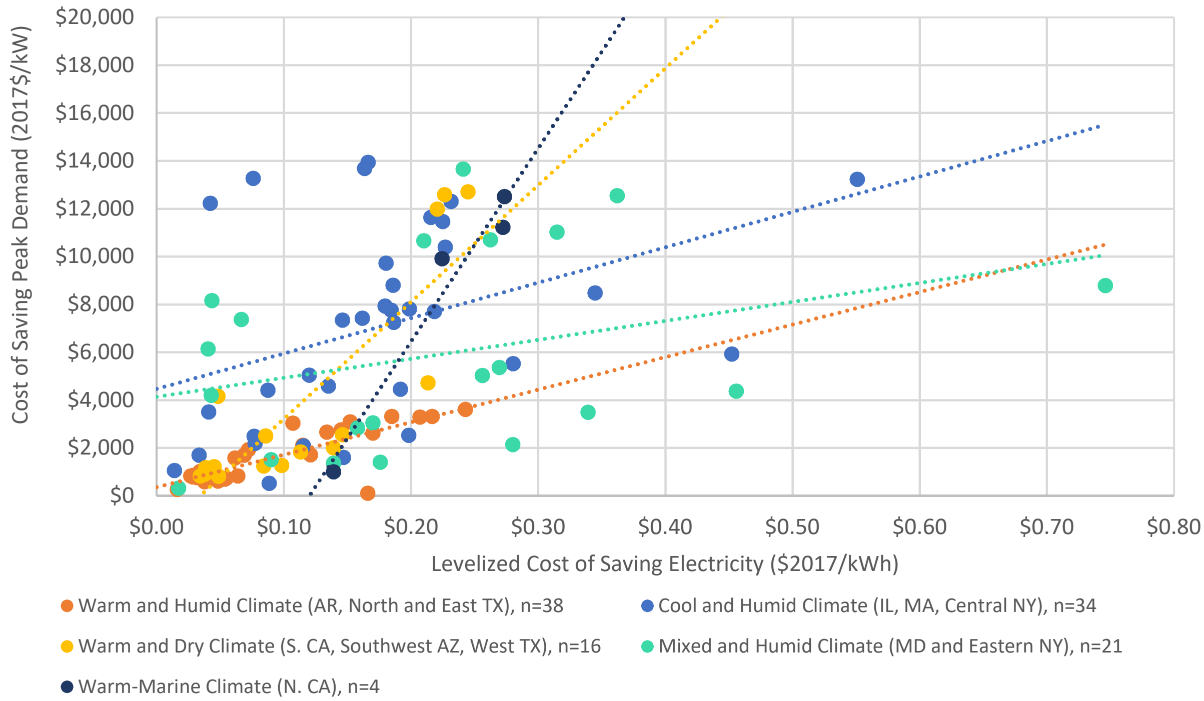


3.2.7 Low-Income Programs: First-Year Cost of Saving Peak Demand

Figure 3-9 shows CSE and first-year CSPD results for low-income programs offered by program administrators in five climate zones. Many low-income programs with the lowest first-year CSPD values are located in Texas, and to some degree in Colorado and Arkansas.[33] In our sample, low-income programs have the most expensive first-year CSPD and levelized CSE. Program values range widely, particularly in mixed and humid, and cool and humid, climate zones. These results suggest that overall program design and measure mix are the largest influences on first-year CSPD for low-income programs, although climate zone has some impact on first-year CSPD values.

[33] Low income program results for Colorado are not included in Figure 3-9 because our sample for this climate zone has too few program years of data.

Figure 3-9. Low income programs: first-year cost of saving peak demand



3.3 First-Year Cost of Saving Peak Demand: Potential Impact of Peak Demand Definition

As discussed in Section 2.3, we investigated and compiled information on each program administrator or state's definition of peak demand and peak period, such as months and peak period hours, and grouped states together by definition (see Table 3-1). Our objective was to identify if there is a relationship between first-year CSPD and the duration and number of hours in the peak period.

We created three groups for our nine-state sample based on peak demand definition:

- Group 1 defines a summer peak period that covers 498 hours in June through September.
- Group 2 defines a summer peak period that includes 256 hours in June through August.
- Group 3 includes states that use other definitions of summer peak period.[34]

[34] Peak period definitions may not always come from utility filings we used to collect information on peak demand savings for energy efficiency programs. For example, in Arizona, utility filings do not provide a peak period or approach for determining peak demand reductions. Therefore, we used peak periods applicable to time-of-use rates in Arizona (see Table B - 4). In Colorado, utility filings provide demand savings information, but do not define the terms. We used the peak period hours that Xcel Energy identified in its 2017 All-Source Solicitation.

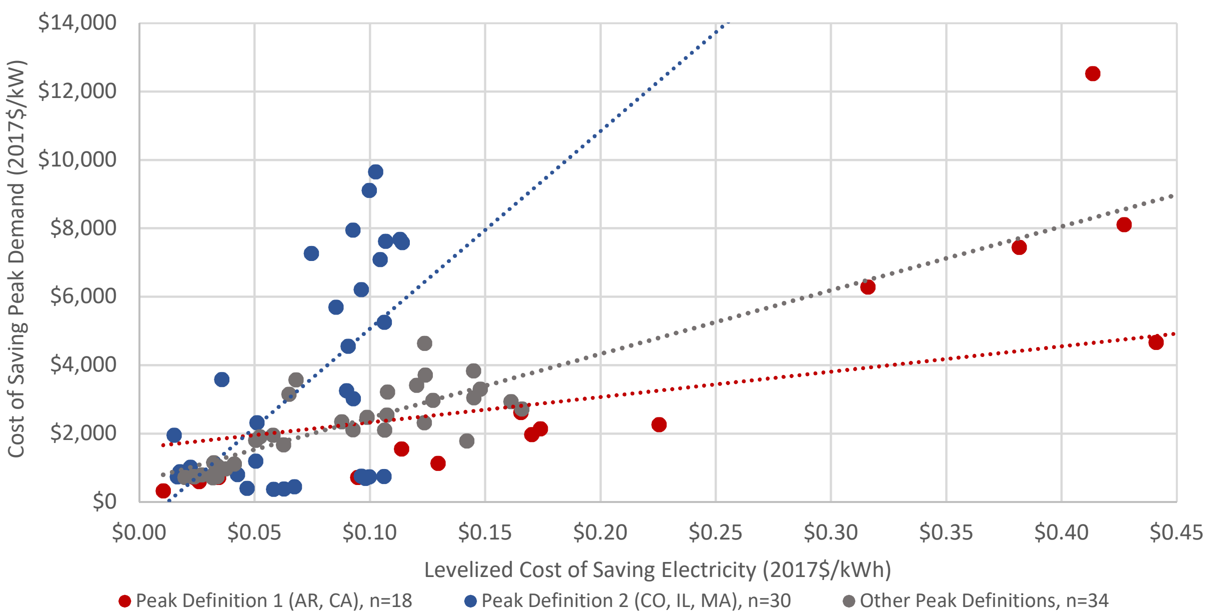
Table 3-1. Duration of peak period

Peak Period Duration Group 1 498 summer peak period hours	Peak Period Duration Group 2 256 summer peak period hours	Peak Period Duration Group 3 (other definitions)
Arkansas	Colorado	Arizona
California	Illinois	Maryland
	Massachusetts	New York
		Texas

We anticipated that average peak demand savings would be lower in states with more peak hours (Group 1) compared to locations with fewer peak hours (Group 2). However, this initial exploratory analysis did not indicate any relationship between first-year CSPD and duration and number of hours in the peak period. Further, the analysis clearly showed definitions of peak demand and peak period alone (e.g., months and peak period hours) are insufficient for comparative analysis. Additional information is needed on methods program administrators used to calculate peak demand savings during peak hours — specifically, whether administrators are quantifying peak demand impacts for the single highest hour during the defined peak period, as an average across all hours in that period, or using another method.

For illustrative purposes, groups first-year CSPD and levelized CSE values for residential HVAC programs by peak definition period: Group 1 (Arkansas, California), Group 2 (Colorado, Illinois, Massachusetts) and other states (Arizona, Maryland, New York, Texas). The scatterplot looks very similar to Figure 3-6, first-year CSPD and levelized CSE for these programs based on climate zone. Additional information is necessary to understand the relationship between peak demand definitions and first-year CSPD values.

Figure 3-10. Illustrative example of impacts of varying definitions of peak demand on first-year CSPD: residential HVAC



It was outside the scope of this study to further investigate the methods used to calculate peak demand savings. We recommend this as an area of future research. For example, the Northeast Energy Efficiency Partnership's Mid-Atlantic TRM specifies different peak demand periods to assess peak demand reductions for different energy efficiency measures. While we did not identify in our nine-state sample other sources using multiple peak demand periods to determine peak demand impacts, this could be a starting point for better understanding the relationship between the first-year CSPD and peak demand periods.

For our nine-state sample and the seven program types we studied, we conclude that grouping utilities by their definition of peak period does not provide much insight on first-year CSPD values and does not add any explanatory value compared to just grouping utilities by climate zone.

4. Discussion: Next Steps

This study, exploring peak demand impacts of electricity efficiency programs in nine states, demonstrates the potential for estimating, evaluating and reporting the first-year cost of saving peak demand at the utility and program level. This information could serve as an important new resource for utilities, state decision makers, ISOs/RTOs, and stakeholders. We are not aware of other program-level estimates of peak demand savings from efficiency or for the first-year cost of saving peak demand.[35]

The levelized CSE values average $0.029/kWh and vary by a factor of three ($0.013/kWh to $0.039/kWh) across the nine states. These results generally align with previous Berkeley Lab studies. The first-year CSPD values average $1,483/kW and vary by a factor of more than four ($568/kW to $2,353/kW) across the nine states. This illustrates that program costs are the primary driver of relative differences in first-year CSPD across states, although the level of peak demand savings (per program dollar invested) appears to have some impact as well.

In this limited study, we could not determine the extent to which differences in peak demand savings per program dollar invested are due to climate severity or methods used to estimate peak demand savings, given limited transparency, limitations in reporting practices, and inconsistency in methods used to define and estimate peak demand savings. Historically, most states have not focused on developing consistent, well-documented methods to estimate, verify, and report peak demand savings. Thus, we view these first-year CSPD results as an initial effort, with values likely to be indicative of relative differences across states and types of programs. Ultimately, in addition to other attributes and benefits, electricity efficiency programs (and measures) can more robustly serve as peak demand reduction resources if there are increased efforts to measure and verify their location- and time-sensitive demand impacts.

This study highlights a number of issues that states and utilities and other program administrators should consider addressing if they want to improve practices in estimating, documenting, and reporting peak demand savings for electricity efficiency programs. We highlight these issues and opportunities for improvement in the next sections.

4.1 Defining Peak Demand: Multiple Applications and Needs

In reviewing definitions of peak demand period and their relationship to calculating peak demand savings, we found a general lack of clarity. In annual reports on electricity efficiency programs filed by utilities with state public utility commissions, we had difficulty in many cases locating the peak demand definitions used to assess peak demand savings. We often had to seek out additional sources such as TRMs and other EM&V guidance, tariff sheets, and statutes to identify these definitions.

[35] The U.S. Energy Information Administration (EIA) publishes data on utility peak demand reductions from efficiency programs by sector in its Form EIA-861.

In addition, utilities and ISOs/RTOs develop definitions of peak demands to meet multiple objectives that satisfy various planning and operational requirements and needs (e.g., reliability criteria for generation and transmission planning, criteria for planning distribution system investments, and time periods that customers need to curtail loads in order to participate in a demand response program). Thus, over time, it may be necessary for utilities to have the capacity to calculate peak demand savings for electricity efficiency programs using more than one definition of peak period. For example, ISO-New England is working with stakeholders to develop a method to estimate hourly energy efficiency savings for use in capacity performance payments (Yoshimura and Smith 2019).[36] Public utility commissions could require utility filings for electricity efficiency programs to state the peak demand definition they are using in estimating peak demand savings and whether and how the definition is consistent across filings.

For example, are peak demand savings estimates based on coincidence with an ISO/RTO system or an individual electric utility's bulk power system, or on local distribution system peaks? Over the long term, given the diversity between system peaks and local peaks, which are relevant for transmission and distribution systems, respectively, the ability to measure hourly savings provided by energy efficiency programs (or measures) is becoming increasingly important.

4.2 Reporting Peak Demand Savings

Today, many states do not emphasize reporting of peak demand savings for their electricity efficiency programs. If a state public utility commission requires utilities under its jurisdiction to report peak demand impacts of these programs in their annual reports, with clear and consistent definitions, this information can be used to better target programs to meet peak demand at least cost. For this activity to be meaningful, states will need to devote additional effort to improving their TRMs in terms of documenting peak demand savings, updating sources and data on peak demand savings, and conducting and updating studies on coincidence factors for various types of efficiency measures.

Further, states that do not have a TRM or are looking to improve an existing TRM can consider the potential benefits of a regional approach to such documents — economies of scale, additional resources for creating high quality products and services, consistency in terminology, and consistent reporting format and content — which in turn can support higher levels of efficiency activity. Examples of regional approaches include the Northwest Regional Technical Forum and Mid-Atlantic Technical Reference Manual (Schiller et al. 2017).

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[36] In 2018, the NEPOOL Markets Committee was presented with different approaches to address settlement imbalances associated with the treatment of energy efficiency resources in connection with the calculation of Capacity Performance Payments during Capacity Scarcity Conditions that occur during off-peak hours. In March 2019, the Markets Committee instructed the ISO-NE Demand Resources Working Group to consider how energy efficiency resource performance in all hours for existing and new measures could be established. For more information see Yoshimura and Smith (2019).

4.3 Next Steps

This study represents an initial effort to collect and analyze data on the peak demand impacts of electricity efficiency programs. Potential future directions for analysis of the cost of saving peak demand include the following:

- *Bigger and more diverse sample.* Collecting and analyzing data on peak demand savings for efficiency programs from additional states would provide broader geographic representation, larger sample size, more diversity and greater confidence in results.
- *Additional research into approaches, calculations and definitions.* While reviewing peak demand savings estimates and TRMs, it became clear that multiple approaches are used for various measures to estimate peak demand impacts. However, it was not always clear which approach was used for certain measures or programs. It was even more challenging to find information on how utilities that do not have a TRM calculate peak demand savings. It was beyond the scope of this study to conduct a broader set of interviews with PUC staff, utilities and EM&V contractors to verify how peak demand savings are being calculated, but that would be one way to improve data quality for future studies. Because coincidence factors are widely used to derive peak demand impacts, we also could dig deeper into how TRMs calculate coincidence factors, and the basis and data sources for these calculations, and compare various calculation approaches for reported peak demand impacts (e.g., coincidence factors versus end use metering data).
- *Total cost of saving peak demand*. With a very modest budget for this first-ever analysis, we were not able to collect participant costs and calculate the *total* cost of saving peak demand (program administrator costs plus participant costs). Because we would only be able to collect participant costs for a subset of programs (see Hoffman et al. 2018), we would need a larger sample of utilities and programs (beyond our nine-state sample for this study) to perform the analysis.
- *Lifetime cost of saving peak demand.* For this study, we only considered peak demand savings in the first year; we did not develop a metric to capture the value of peak demand savings over the program's lifetime. In future research, we could explore metrics that would reflect the lifetime demand-savings weighted CSPD, or a metric similar to how the Energy Information Administration (EIA) and Lazard calculate the levelized cost of energy (Lazard 2018; EIA 2019).
- *Winter peaking systems.* Our initial analysis of the first-year cost of saving peak demand focused on summer months. We could expand our analysis to winter months, to determine value for that season and for winter- or dual-peaking U.S. electricity systems.
- *Peak-to-energy ratios:* Determining peak (kW) to energy (kWh) ratios would be helpful for benchmarking efficiency programs designed in part to reduce peak demand.
- *Case studies.* Examining selected utility programs in detail — particularly those introduced in recent years to address the shifting focus to the time-sensitive value of efficiency — would provide insight into successful program design and implementation to successfully achieve targeted peak demand reductions.

- *Guidance documents.* We could build on Berkeley Lab tools for data collection and reporting on efficiency program costs and savings (Rybka et al. 2015) to provide templates for states, utilities, and other program administrators to improve reporting on peak demand savings and costs. In particular, we could collaborate with state PUCs, utilities, and stakeholders to develop guidance for consistent methods to define peak periods and calculate and report peak demand savings.

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APPENDIX A. Program Data for States Included in This Study

Appendix A summarizes the data used in this study.

Table A - 1. Summary of electricity efficiency program data used for this study[37]

State	First Year of Data	Last Year of Data	Number of Utilities/ Program Administrators	Total Program Years	Program Years Used in PA CSE (reporting electricity savings)	Program Years Used in PA first-year CSPD (reporting peak demand savings)
AR	2014	2017	3	118	89	88
AZ	2014	2017	3	185	150	149
CA	2014	2017	3	767	544	539
CO	2014	2017	1	191	133	132
IL	2014	2016	2	114	104	79
MA	2014	2017	4	660	272	240
MD	2014	2017	4	291	269	258
NY	2014	2017	7	199	151	108
TX	2014	2017	9	383	311	308
			36	***2,908***	***2,023***	***1,901***

[37] For example, for this study we assume that all utilities in Arkansas used the peak demand period specified by Entergy Arkansas, LLC, because it was the only utility that provided months and hours in documentation. Program data for Illinois were available for the entire study period (2014 to 2017), but program year 2016 and 2017 reports were combined and not easily separable by year. In California, the available dataset from the Public Utilities Commission for PY 2017 did not include sufficient data for Pacific Gas & Electric to distinguish its program spending by fuel. Thus, we excluded those data. However, the utility's reporting for low-income programs separates spending by fuel, so we included PG&E data for PY 2017 low-income programs. In the total sample, some programs reported costs and not savings, as discussed in Section 2.3.

APPENDIX B. Definitions of Peak Demand and Peak Demand Reductions

Appendix B first summarizes a variety of approaches to estimating peak demand reductions (Table B - 1), then cites various definitions of peak demand, including coincidence factors (Table B - 2) used by a broad group of utilities and other program administrators, state public utility commissions, Federal entities, and ISOs/RTOs.

Table B - 3 provides the peak demand periods, including the number of days and total number of hours, for the nine states covered by this study. Table B - 4, Table B - 5, and Figure B - 1 and present information on climate zones for these states.

Table B - 1. Approaches to estimating peak demand reductions: Uniform Methods Project

Source: Stern and Spencer 2017.

Approach	Relative Cost	Relative Potential Accuracy	Comments
Engineering Algorithms	Low	Low-Moderate	Accuracy depends on the quality of the input assumptions as well as the algorithm. Appropriate for prescriptive measures with good existing data.
Calibrated Hourly Simulation Modeling	Moderate	Moderate	Input assumptions are again important—garbage in, garbage out; appropriate for HVAC and shell measures and HVAC interaction
Billing Data Analysis with Load Shapes	Moderate	Moderate	Typically not directly useful for peak demand or on/off peak energy analysis, but it can be used to leverage other approaches
Interval Metered Data Analysis	Moderate	High	Interval metered data is not available for many customers; it is becoming more feasible with proliferation of advanced metering infrastructure (AMI). Appropriate for residential retrofit programs with HVAC and shell measures.
NILM	Moderate	Moderate	Considered significantly less accurate than direct end-use metering, but less expensive. Most applicable for residential cooling.
End-Use Metered Data Analysis	High	High	Requires careful sampling and consideration of period to be metered. Most applicable to high impact prescriptive measures.
Survey Data on Hours of Use	Low-Moderate	Low	Only applicable in the rare cases when customers can provide better estimates than other available data.

Table B - 2. Peak demand definitions

Reporting entity and source	Term	Definition
Arizona Statute	Demand reduction	The load reduction, measured in kW, occurring during a relevant peak period or periods as a direct result of energy efficiency and demand response programs.
Arkansas TRM	Description	"If demand savings are to be calculated, the choice of definition (e.g., annual average, peak summer, coincident peak, etc.) is related to time granularity."
Arkansas TRM	Annual average demands savings	"Total annual energy (MWh) savings divided by the hours in a year (8760)."
Arkansas TRM	Coincident demand	"The metered demand of a device, circuit or building that occurs at the same time as the peak demand of a utility's system load or at the same time as some other peak of interest, such as building or facility peak demand. This should be expressed in a way that indicates the peak of interest (e.g., demand coincident with the utility system peak)."
Arkansas TRM	Coincident peak demand reductions	"The demand savings that occur when the servicing utility is at its peak demand from all (or segments) of its customers. This indicates what portion of a utility's system peak demand is reduced during the highest periods of electricity consumption. Calculating coincident peak demand requires knowing when the utility has its peak (which is not known until the peak season is over)."
Arkansas TRM	Peak demand	"The maximum level of metered demand during a specified period, such as a billing month or a peak demand period."
Arkansas TRM	Peak demand reductions	"The maximum amount of demand reduction achieved during a period of time. This time period should be clearly defined, whether it is annual, seasonal, or during a specific period of time, such as a summer weekday afternoon or winter peak billing hours."
Arkansas utility DSM filings: OGE, Entergy Arkansas LLC, SWEPCO	Demand savings: Customer kW max	"Demand that did not occur due to the installation of an energy efficiency measure (non-coincident peak)."
Entergy Arkansas LLC[38]	Peak demand period	The summer peak period is defined weekdays from 1 p.m. to 7 p.m. starting on June 1st and ending on September 30th.
Federal Energy Regulatory Commission (FERC)	Peak load, peak demand	These two terms are used interchangeably to denote the maximum power requirement of a system at a given time, or the amount of power required to supply customers at times when need is greatest. Refers either to the load at a given moment (e.g., a specific time of day) or to average load over a given period of time (e.g., a specific day or hour of the day). Usually expressed in megawatts.
SWEPCO (Arkansas) – Load Management Program description	Peak demand period	The Program Period is defined as June 1 through September 30, excluding weekends and holidays.
California – CPUC EE Policy Manual	Peak demand savings	The definition of peak megawatt load reduction contained in the most recently adopted DEER shall be used to estimate and

[38] Correspondence with Arkansas Public Service Commission staff, December 2018.

Reporting entity and source	Term	Definition
		verify peak demand savings values. The DEER method utilizes an estimated average grid level impact for a measure between 2 p.m. and 5 p.m. during a "heat wave" defined by three consecutive weekdays for weather conditions that are expected to produce a regional grid peak event.
California CPUC resolution[39]	Peak demand savings (effective 1/1/2020)	A shift in the time period used in the DEER definition of demand reduction from 2 p.m. to 5 p.m. to 4 p.m. to 9 p.m. is both feasible and reasonable. A shift in the selection of days in the DEER definition of demand reduction is not feasible in the time available, or the resources and information available for a January 1, 2020, effective date. Additionally, such a shift is not adequately supported by the record at this time.
Energy Information Administration (EIA)	Coincidental demand	"The sum of two or more demands that occur in the same time interval."
EIA	Coincidental peak load	"The sum of two or more peak loads that occur in the same time interval."
EIA	Non-coincident peak load	"The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for no more than a year."
ERCOT Billing Determinant Data Elements	4-Coincident Peak (CP)	"Average 4-CP is defined as the average Settlement Interval coincidental MW peak occurring during the months of June, July, August and September. Settlement Interval MW coincidental peak is defined as the highest monthly 15 minute MW peak for the entire ERCOT Transmission Grid as captured by the ERCOT settlement system."
Illinois TRM	Coincident summer peak	Illinois is in MISO and PJM. "As PJM has a forward capacity market that allows energy efficiency to participate, and because ComEd is in PJM's territory, the IL TRM adopts ComEd's definition of summer peak for the purposes of the TRM. The summer peak period is "1- 5pm Central Prevailing Time on non-holiday weekends, June through August."
Illinois PAs	Peak demand	Commonwealth Edison uses the term peak demand in most of their EM&V reports, but does not define it. Ameren does not use the term peak demand, but does use a coincidence factor to calculate demand savings. Ameren does not define demand savings.
ISO-New England	Peak Demand Period	Summer on-peak period is defined as non-holiday weekday hours ending 1400 through 1700 during June through August while the winter on-peak period is defined as non-holiday weekday hours ending 1800 through 1900 during December and January.

[39] The California Public Utilities Commission (CPUC) adopted a new definition of peak demand for the DEER database on October 11, 2018, effective January 1, 2019. The data that we gathered for this report used the prior DEER definition of peak demand, shown in the table. For more information on the new DEER peak demand definition, see CPUC Resolution E-4952, docs.cpuc.ca.gov/PublishedDocs/Published/G000/M232/K459/232459122.PDF.

Reporting entity and source	Term	Definition
Maryland EmPower glossary[40]	Coincident Peak Demand Savings	The total incremental reported demand savings for a program in MW.
Maryland Hours of Use Lighting Study	Peak demand definition	Non-holiday weekdays from July 1 – August 21, 4:00 PM to 5:00 PM
Mid-Atlantic TRM (Maryland, Washington DC, and Delaware)	Non-weather sensitive measures peak savings	Peak savings are estimated as the average of savings between 2 pm and 6 pm across all summer weekdays.
Mid-Atlantic TRM	Cooling measures peak savings	Peak savings are estimated during the most typical peak hour (assumed here to be 5 p.m.) on days during which system peak demand typically occurs (i.e., the hottest summer weekdays).
Maryland Statute Section 7-211 (a)(5)	Peak demand	The highest level of electricity demand in the State measured in megawatts during the period from May 1 to September 30 on a weather–normalized basis.
Massachusetts TRM	Summer on-peak demand	Average demand reduction from 1-5 pm on non-holiday weekdays in June-August.
Massachusetts TRM	Coincidence factor	The coincidence factor "adjusts the connected load kW savings derived from the savings algorithm. A coincidence factor represents the fraction of the connected load reduction expected to occur at the same time as a particular system peak period. The coincidence factor includes both coincidence and diversity factors combined into one number, thus there is no need for a separate diversity factor in this TRM" (page 12).
Minnesota TRM	Coincidence factor, electric peak coincidence factor, deemed coincidence factor, deemed peak demand coincidence factor	These terms appear to be used interchangeably throughout the TRM. Coincidence factor is only defined in the TRM for commercial and industrial lighting measures. The definition provided is "the probability that peak demand of the lights with coincide with peak utility system demand."
Minnesota TRM	Peak demand savings	For the majority of measures, calculated by multiplying the measure kW savings by the coincidence factor (often deemed).
MISO Module A of tariff	Coincident peak demand	"The demand in MWs, for a load serving entity and/or electric distribution company that occurs coincident to the annual peak demand in the Transmission Provider Region, where all demand has been augmented to include any known reductions in demand related to load modifying resources and/or energy efficiency resources."
New Jersey Clean energy protocols	Coincident Peak Demand Savings	"Summer coincident peak demand savings are calculated using a demand savings protocol for each measure that includes a coincidence factor. Application of the coincidence factor converts the demand savings of the measure, which may not occur at time of system peak, to demand savings that is expected to occur during the Summer On-Peak period." The summer peak period is defined as 12-8 p.m., June through August.

[40] Received through correspondence with Maryland Public Service Commission staff.

Reporting entity and source	Term	Definition
New York DPS Reporting Guidance	Gross peak demand	The MW demand savings that are associated with an energy saving measure or project and that occur during the hour ending at 5 pm on the hottest non-holiday weekday. The peak day can occur in June, July, or August - depending on the weather. Program Administrators should calculate peak demand savings based on the hottest summer non-holiday weekday during the hour ending at 5 pm. Savings have not been adjusted for free-ridership, spillover or realization rates. Savings are considered acquired when the funds associated with the measure or project have been spent (i.e., a rebate check has been sent to the participant on a specific date or the PA has authorized payment for the project).
Pennsylvania TRM	Coincident peak demand savings	June through August (excluding weekends and holidays); 2-6 pm. Summer coincident peak demand savings from energy efficiency are calculated using a demand savings algorithm for each measure that includes a coincident factor.
PJM	EE Performance Hours	The expected average load reduction (MW) during the defined summer Performance Hours which are weekday hours between the hour ending 15:00 and the hour ending 18:00 PT during June through August and winter weekday hours (January and February) between the hour ending at 8:00 and 9:00 and between 19:00 and 20:00.
Rhode Island TRM	Net summer/winter peak demand savings	Starts with coincidence factors for winter and summer peaks: A coincidence factor adjusts the connected load kW savings derived from the savings algorithm. A coincidence factor represents the fraction of the connected load reduction expected to occur at the same time as a particular system peak period. The coincidence factor includes both coincidence and diversity factors combined into one number, thus there is no need for a separate diversity factor in this TRM. Coincidence factors are provided for the on-peak period as defined by the ISO New England for the Forward Capacity Market ("FCM"), and are calculated consistently with the FCM methodology. Electric demand reduction during the ISO New England peak periods is defined as follows: • Summer On-Peak: average demand reduction from 1:00-5:00 PM on non-holiday weekdays in June July, and August • Winter On-Peak: average demand reduction from 5:00-7:00 PM on non-holiday weekdays in December and January The values described as Coincidence Factors in the TRM are not always consistent with the strict definition of a Coincidence Factor (CF). It would be more accurate to define the Coincidence Factor as "the value that is multiplied by the Gross kW value to calculate the average kW reduction coincident with the on-peak periods." A coincidence factor of 1.00 may be used because the coincidence is already included in the estimate of Gross kW; this is often the case when the "Max kW Reduction" is not calculated and instead the "Gross kW" is estimated using the annual kWh reduction estimate and a

Reporting entity and source	Term	Definition
		loadshape model. Calculation of Net Summer Electric Peak Demand Coincident kW Savings net_kWSP = gross_kW × SPF × ISR × RRSP × CFSP × NTG • Calculation of Net Winter Electric Peak Demand Coincident kW Savings net_kWWP = gross_kW × SPF × ISR × RRWP × CFWP × NTG
Rocky Mountain Power Utah DSM filing)	Estimated peak contributions	Estimated MW impact of energy efficiency portfolio during PacifiCorp's system peak period. An energy-capacity conversion factor (0.000189 Coincident MW/MWh) developed from EE selections in the 2015 IRP is used to translate 2017 energy savings to estimated demand reduction during the system peak.
SEE Action	Peak demand savings	"The demand reduction produced by an energy efficiency measure that is coincident with a utility system's peak period, which may occur over one or more hours or days."
SEE Action	Demand savings	The reduction in peak electricity use in units of kW or fossil or other fuel (e.g., wood, biomass) use in units of Btu/hour from the baseline to the use associated with the energy-efficient measure installation. May also refer to an energy efficiency measure's coincident peak savings, which is the reduction in peak electricity or other fuel use that occurs simultaneously with the servicing utility system's maximum use during a specific period (i.e., single hour, multiple hours, day, etc.)."
SPP	Forecasted peak demand	"Peak Demand shall be reduced by indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all noncontrollable or non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs)."
Texas TRM	Deemed peak coincident demand savings	Multiple approaches to calculating the peak demand savings from energy efficiency programs are discussed in the Texas TRM. For weather-sensitive measures, the TRM uses a probability-based method developed to identify the top 20 hours when the utility system peaks (referred to as system peak coincident demand) are likely to occur in each of the TRM climate zones. The unadjusted hourly kW savings from energy efficiency measures are used in simulation models. Savings from each hour are paired with that hour's peak demand probability factor. The final attributed demand savings should be estimated as the probability-weighted average of the hourly demand reductions estimated in each of those 20 hours.
Texas TRM	Peak demand reduction	The reduction in demand during times of the utility's summer peak period or winter peak period. Peak demand savings will be calculated based on measure-specific hourly loads during those top hours identified in defining the peak period.
Texas TRM	Peak demand period	The summer peak period is from 1 p.m. to 7 p.m. June-September. The winter peak period is 6-10am and 6 pm-10 pm

Reporting entity and source	Term	Definition
		December–February. Both exclude weekends and Federal holidays.
Uniform Methods Project Chapter 10	Peak demand savings	Peak demand savings are expressed as the average energy savings during a system's peak period
Uniform Methods Project Chapter 10	Time-differentiated energy savings	The energy savings that occur at different times of the day (e.g., morning or evening) or times of the year (e.g., summer or winter).
Xcel (CO) All Source Solicitation for Semi-Dispatchable Renewable Capacity Resources	None	In Xcel Colorado's 2017 All Source Solicitation, hours ending 15-18 are the most valuable. The terms gross customer kW, peak coincident customer kW, gross peak gen kW and gross gen kW are used in the DSM filing, but are not defined.
Xcel (MN) 2017-2019 CIP Plan	Coincidence factor	"Probability that peak demand savings will coincide with peak utility system demand."
Xcel (MN) 2017-2019 CIP Plan	Customer kW peak month Customer kW max	"Average electrical demand savings per household achieved in the month, day and hour that contained the peak demand on Xcel Energy's system." "The maximum of the peak electrical demand savings per household achieved in the summer months: June – September."
Xcel (MN) 2017-2019 CIP Plan	Customer kW savings Generator peak kW savings	"Consumption savings in kW customer realizes after implementing high efficiency product." "Annual kW savings utility realizes on annual peak day after customer implements high efficiency product."

Table B - 3. State and utility peak periods

State/Program Administrator	Peak Period Hours	Peak Period Months	Total Peak Period Days*	Total Peak Period Hours
APS (Arizona)	3–8 pm (res and com)	May 1–October 31	128	640
UNS & TEP (Arizona)	3–7 pm (res) 2–8 pm (com)			512 (res) 768 (com)
Arkansas	1–7 pm	June 1– September 30	83	498
California	noon–6 pm	June 1– September 30	83	498
Colorado	2–6 pm	June 1–August 31	64	256
Illinois	1–5 pm	June 1–August 31	64	256
Massachusetts	1–5 pm	June 1–August 31	64	256
Maryland (statute)	none designated	June 1–September 30	83	N/A
Mid-Atlantic TRM Non-weather sensitive measures	2–6 pm	June 1–August 31	64	256
Mid-Atlantic TRM Cooling measures	4–5 pm	June 1–August 31	64	64
New York	4–5 pm	June 1–August 31	64	64
Texas	Utility peak period	June 1–September 30	1	1

** All states or program administrators define a peak day as a weekday excluding holidays.*

Table B - 4 shows climate zones as defined by ASHRAE (ASHRAE 2017), utilities and other program administrators in our sample; whose service territory is located in each climate zone; and the applicable ISO/RTO region. Figure B - 1 illustrates the climate zones adopted by ASHRAE (ASHRAE 2017) for use in development of building energy codes and equipment standards development. Table B - 5 describes the zones by their climate characteristics.

Table B - 4. Program administrators classified by ISO/RTO region and climate zone

Program Administrator	ISO/RTO Region	Climate Zone Definition
AEP Central (TX)	ERCOT	Hot and humid (2A) 6300 < CDD50°F ≤ 9000
CenterPoint (TX)		
Entergy (TX)	MISO	
Arizona Public Service (AZ)	None	Hot and Dry (2B) 6300 < CDD50°F ≤ 9000
Tucson Electric Power (AZ)		
El Paso (TX)	None	Warm and humid (3A) 4500 < CDD50°F ≤ 6300 and HDD65°F ≤ 3600
Oncor (TX)	ERCOT	
AEP North (TX)		
Entergy Arkansas LLC (AR)	MISO	
Oklahoma Gas & Electric (Arkansas)		
Southwest Electric Power Company (SWEPCO) (AR)	SPP	
SWEPCO (TX)		
Texas New Mexico Power (TX)	ERCOT	Warm and dry (3B) 4500 < CDD50°F ≤ 6300 AND HDD65°F ≤ 3600
UNS (AZ)	None	

Program Administrator	ISO/RTO Region	Climate Zone Definition
San Diego Gas & Electric (CA)	CAISO	
Southern California Edison (CA)		
Pacific Gas & Electric (CA)	CAISO	Warm marine (3C) CDD50°F ≤ 4500 AND HDD65°F ≤ 3600
Baltimore Gas & Electric (MD)	PJM	Mixed and humid (4A) 2700 < CDD50°F ≤ 6300 AND 3600 < HDD65°F ≤5400
Delmarva (MD)		
Pepco (MD)		
Potomac Edison (MD)		
Consolidated Edison (NY)	NYISO	
NYSERDA (NY)		
Orange and Rockland (NY)		
Xcel (TX)	SPP	Mixed and dry (4B) 2700 < CDD50°F ≤ 6300 AND 3600 < HDD65°F ≤5400
Eversource (MA)	ISO-NE	Cool and humid (5A) 1800< CDD50°F ≤ 6300 AND 5400 < HDD65°F ≤7200
Fitchburg Gas & Electric (MA)		
NSTAR (MA)		
Cape Light Compact (MA)		
Commonwealth Edison (IL)	PJM and MISO	
Ameren (IL)		
Central Hudson (NY)	NYISO	
New York State Electric & Gas (NY)		
National Grid (NY)	NYISO	Cold and humid (6A) 7200 < HDD65°F ≤ 9000
Rochester Gas and Electric (NY)		
Xcel (CO)	None	Cold and dry (6B) 7200 < HDD65°F ≤ 9000

Figure B - 1. Climate zones used in building energy code and standards development

Source: ASHRAE 2017; Briggs, Lucas and Taylor 2003

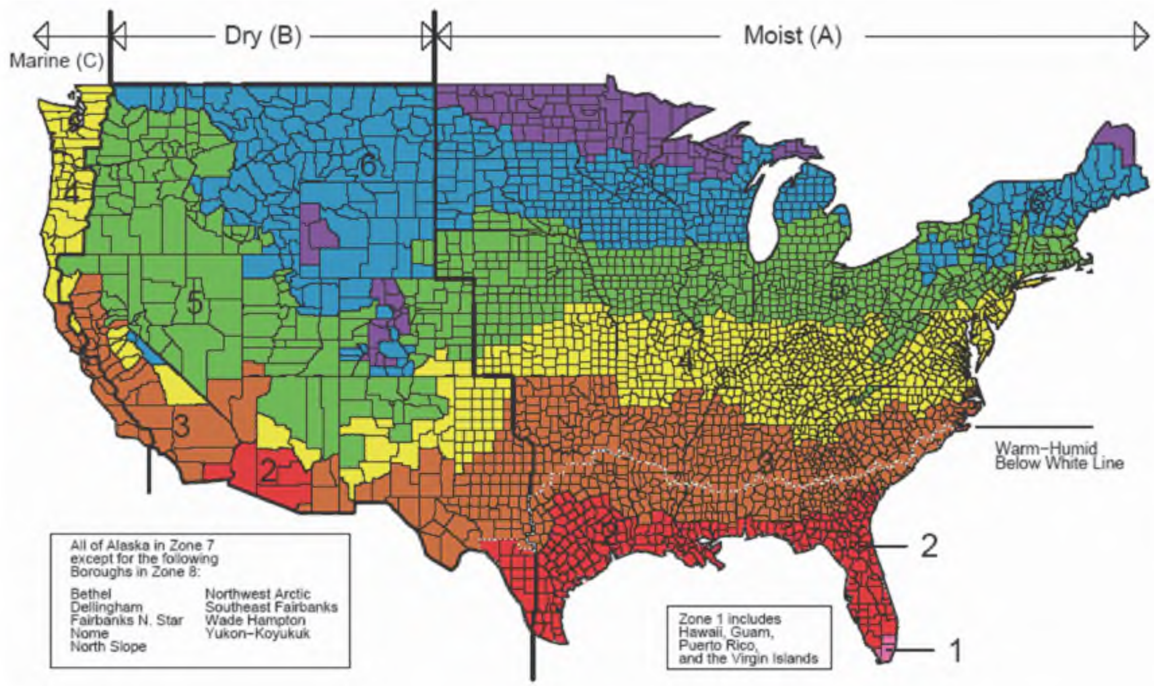

Table B - 5. Definitions and characteristics of building climate zones used by ASHRAE

Zone #	Climate Zone Name and Type
1A	Very Hot – Humid
1B	Very Hot – Dry
2A	Hot – Humid
2B	Hot – Dry
3A	Warm – Humid
3B	Warm – Dry
3C	Warm – Marine
4A	Mixed – Humid
4B	Mixed – Dry
4C	Mixed – Marine
5A	Cool – Humid
5B	Cool – Dry
5C	Cool – Marine
6A	Cold – Humid
6B	Cold – Dry
7	Very Cold
8	Subarctic

APPENDIX C. Illustrative Examples of Levelized Cost of Saving Peak Demand

This study presents results of our first-ever analysis of the cost of saving peak demand using first-year savings. This appendix presents results of calculating the *levelized* CSPD for three types of programs to illustrate the impact of spreading program costs over the effective useful lifetime of measures installed through electricity efficiency programs. Using information developed for this study on the savings-weighted first-year CSPD (from Table 3-2) and program average measure lifetimes from the Berkeley Lab database (Hoffman et al. 2018), we calculated the capital recovery factor to levelize the CSPD. As Table C - 1 shows, the levelized cost of saved peak demand ranges from a low of $94/kW for residential lighting programs to $249/kW for residential HVAC programs (assuming an after-tax weighted average cost of capital of 6%).

Table C - 1. Assumptions used to calculate the levelized cost of saving peak demand

Program Type	First year cost of saving peak demand ($/kW)	Program-average measure lifetime (Years)	Capital recovery factor	Levelized cost of saving peak demand ($/kW)
Residential Lighting	**733**	**10.9**	**0.13**	**94**
C&I Prescriptive Rebate	**1,331**	**13.3**	**0.11**	**148**
Residential HVAC	**2,331**	**14.2**	**0.11**	**249**